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Simulation-Driven Operational Value Optimization Within Design Constraints: A Case Study in Applying Dynamic Stage Lengths at Execution Pace

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Abstract

Execution optimization for completions operations is often under-addressed. While asset development optimization (focusing on parameters that impact production such as well spacing, lateral lengths, and macro stage design) is essential in the maximization of well performance and economics, further optimization opportunities remain. These opportunities are typically unrealized due to the operational demands and traditional planning software programs' lack of focus on completions process simulation and cost estimation. While ensuring development requirements are not violated, this work uniquely focuses on execution optimization. Novel software, distinctively capable of empowering overextended, operations-focused engineers to perform optimizations previously impractical to perform. Quick analyses with high-level assumptions have been transformed into quick analyses with extensive detail and accuracy. Specifically, this paper documents a reproducible workflow for increasing stage length (by holding cluster spacing constant and increasing clusters per stage) throughout a lateral while maintaining development constraints. Representative completions cycle time and cost reductions are quantified. It is found that cycle time and cost reductions of 6.3% and 2.3% per well can be realized.

Introduction

In upstream planning, asset development optimization traditionally garners a great deal of attention. Subsurface teams work to determine how to maximize well performance (well spacing, stage design, etc.). They collaborate with subject matter experts from various disciplines (e.g., drilling, completions, etc.) to combine cost and cycle time estimates with economists' models to evaluate financial metrics (Net Present Value, 3-Yr Free Cashflow, etc.) to pick standard designs and strategies for various benches. Many excellent analyses and workflows have been documented [Baosheng (2019), Belyadi (2018), Jaripatke (2014), Miller (2022), Morsy (2022)] and, though the emphasis is primarily maximizing well performance, there are multiple established commercial software to assist (ResFrac, ComboCurve, Novi Labs, Enersight, PRISM, etc.).

The results of asset development optimization typically include standard sand and water loading (on a per-unit basis, e.g. lb/ft and bbl/ft), cluster spacing (ft), and a stage's minimum flow rate per cluster (e.g., bbl/min/cluster). The minimum flow rate per cluster is driven by limited entry targets and fracture geometry one aims to achieve with a given design. I.e., a target pressure drop across a stage's perforations is required to ensure all the clusters are "effective" (i.e., that all the clusters take fluid and proppant and, therefore, produce). When combined with a perforation design (e.g., shots per cluster and perforation diameter), a targeted perforation friction (i.e. the pressure drop across the perforations) corresponds to a minimum flow rate per cluster. The designs then determine the maximum permitted stage length (knowing that completing a lateral with longer stages is generally more time and cost effective). While there may be some small, permitted window around sand and fluid loading and perhaps leniency to pump under the bbl/min/cluster for the first few stages per well (while limited by pipe friction), these designs are typically held as firm constraints.

Within these asset development design constraints there remain many operational and some design opportunities for further optimization. These execution optimizations are design and strategy options believed to largely not affect production but can potentially reduce operational risk, cost, and cycle time. In the specific case of dynamically changing stage lengths, there is an additional benefit of increasing treatment uniformity from the toe to the heel. These execution optimizations are rarely thoroughly performed. There are at least three reasons.

a. The problems are complex due to the high number of complex interactions. E.g., this paper will focus on varying clusters per stage which changes stage length. Changing stage length affects at least the following.

    a. Number of stages per lateral
    b. Pumping time per stage
    c. Perforation friction
    d. Precise measured depths of stages and clusters
    e. Because of the above, the achievable pumping flow rate and/or pressure
    f. Amount of non-treatment pumping phases (breakdowns, flushes, etc.)
    g. Number of plugs and wireline runs
    h. Possibly cycle time (depending on critical path activities)

b. Execution subject matter experts are typically busy monitoring ongoing and planning future operations. Standard planning and troubleshooting activities leave little time for stage-specific optimization.
c. Until recently, there has been no commercial planning software sufficiently focused on execution problems and solutions. Upstream planning software is primarily focused on predicting and maximizing well performance (e.g., geology, fracture propagation, etc.) and network optimization. For completions teams to plan and understand design adjustments, engineers primarily use in-house spreadsheets that lack incorporation of pumping physics, process logic, and contractual obligations to easily capture precise impacts on logistics, cost and cycle time needed to make informed and optimal decisions.

The time requirements to account for the complex iterations and lack of sophisticated software to support such endeavors result in remaining optimization opportunities.

One common execution optimization opportunity is designing to a variable stage length (varying number of clusters per stage while holding cluster spacing) from toe to heel on a given lateral (henceforth, "dynamic stage lengths"). In most circumstances, the lowest achievable hydraulic pumping flow rate per stage is at the toe stage (the stage at the deepest measured depth). At this stage, there is the most pressure loss due to pipe friction. As operators gradually work towards the heel (the stage at the shallowest measured depth), pipe friction is reduced, and the flow rate can gradually increase. Flow rate is generally maximized because the cost and time savings of pumping the same amount of water and sand in a shorter time outweigh alternatives (e.g., reducing friction reducer usage or allowing hydraulic pumping pressure to decrease). Other limiting factors (e.g., frac fleet capability, frac tree limitations, etc.) can eventually cap the flow rate at which point the treating pressure will reduce as operations move uphole.

As flow rate increases moving from toe to heel, it is possible that, at one or more points in the lateral, an additional cluster could be added (increasing the stage length) and still maintain the asset development design constraint of a minimum flow rate per cluster. Increasing some stage lengths will generally lead to a reduction in completions costs, pad cycle time, and risk (fewer plugs, flushes, wireline runs, etc.).

Even though it is common knowledge that increasing stage length as one moves closer to the heel has execution benefits, it is not common practice. This is largely due to the challenges outlined above. Operators could, in theory, monitor real-time pumping flow rates and, when within asset development design constraints, increase the clusters per stage soon thereafter. But being this flexible is challenging to execute. Operators need to have an estimation of stage designs and pumping plans further in advance to prepare service and equipment providers. And, due to the three reasons outlined above, this execution optimization is rarely performed.

However, Devon engineers adopted software, PrePad™, that has enabled execution optimizations such as dynamic stage spacing in minutes. This paper will outline how simulation is used to predict precise flow rates and, when combined with a designed minimum flow rate per cluster, the maximum number of clusters possible per stage without violating asset design constraints. This includes, when increasing stage length by adding a cluster of the designed cluster spacing, also maintaining sand and water loading targets. After describing the generic algorithm, a representative base case will be documented, and the standard workflow iterations will be executed and documented.

Further, within the PrePad™ software platform, these stage design adjustments are combined with a comprehensive cycle time and capital expense estimator so expected achievable value (in terms of reduced cycle time and reduced cost) can be quantified. The cycle time and cost estimates for the base case and final optimized design will be documented—including how and why the estimates are what they are.

Although the benefits can vary widely based on the specific circumstances (e.g., lateral length, stage design, fracture gradient), Devon has been realizing cycle time and cost reductions in ranges consistent with those quantified in this case study: up to 10% increases in execution speed and 3% completions cost reductions per well.

Definitions and Assumptions

Perhaps the most important aspect of the simulation software for this execution optimization workflow is the first-principles physics models used to predict hydraulic treating pressures and slurry flow rates (P_{hyd} and Q_{hyd}). There are three fundamental physics equations that drive the simulation software's predictions. All recorded equations assume SI units.

The first is the Darcy–Weisbach pressure drop equation (Brown, 2002)

$$\frac{P_{friction}}{L} = f_D \cdot \frac{\rho}{2} \cdot \frac{v2}{D_H}$$

where

P_{friction}	[Pa] is the pressure loss due to pipe friction,
L	[m] is the pipe length,
f_D	[kg/m] is the Darcy friction factor,
ρ	[kg/m^3] is the density of the fluid,
#v#	[m/s] is the mean flow velocity of the fluid in the pipe, and

D_H [m] is the hydraulic diameter of the pipe.

The second is, because the flow is turbulent (i.e., the Reynolds number is greater than 2300), the Colebrook friction equation (Brown, 2002).

$$\frac{1}{f_D^{1/2}} = -2 \cdot \log\left(\frac{2.51}{\mathrm{Re} \cdot f_D^{1/2}} + \frac{\frac{k}{D_H}}{3.72}\right)$$

where

Re is the Reynolds number and

k [m] is the roughness of duct, pipe, or tube surface.

The third key equation is based on the conservation of pressure law.

$$P_{\mathrm{hyd}} = P_{\mathrm{fg}} + P_{\mathrm{perf}} + P_{\mathrm{orifice}} + (K_{\mathrm{red}} \cdot P_{\mathrm{friction}}) + P_{\mathrm{tort}} - P_{\mathrm{hs}}$$

where

P_{hyd} [Pa] is the hydraulic pumping pressure,

P_{fg} [Pa] is the pressure due to frac gradient,

P_{perf} [Pa] is the pressure drop due to perforation friction,

P_{orifice} [Pa] is the cumulative pressure drop due to orifices in lateral,

P_{friction} [Pa] is the cumulative pressure drop due to friction if no friction reduction additives,

K_{red} (0-100%) is the percentage of pressure drop due to friction due to friction reduction additives,

P_{tort} [Pa] is the pressure due tortuosity of fracture paths, and

P_{hs} [Pa] is the hydrostatic pressure of vertical fluid column.

In this case study, no sleeves were used (e.g., all stages used plug-and-perforate technology to access the formation and isolate the stage), so P_{orifice} is ignored. Technically, there must be at least one P_{friction} per change in frac casing properties (that is, the casing through which is frac'ed), but, for this example, a 5.5-inch monobore is used, so one P_{friction} is sufficient.

The perforation friction, P_{perft}, is calculated using

$$P_{\mathrm{perf}} = \frac{\rho}{2} \cdot \left(\frac{Q_{\mathrm{hyd}}}{C_d \cdot A}\right)^2$$

where

Q_{hyd} [m^3/s] is the hydraulic pumping slurry flow rate,

A [m^2] is the effective access area per stage, and

C_d is the average shot discharge coefficient

and with

$$A = n \cdot \pi \cdot \left(\frac{D}{2}\right)^2 \cdot \mathrm{CPS} \cdot \mathrm{ClustEff}$$

where

n is the number of shots per cluster,

D [m] is the average diameter per shot,

CPS is the number of clusters per stage, and

ClustEff (0-100%) is the cluster efficiency (what % of clusters take water and sand).

Using the above, given a stage's particular measured depth and perforation design, true vertical depth and frac gradient, casing internal diameter, fluid density and viscosity, and assumptions regarding shot discharge coefficient and fluid system's reduction of pressure due to pipe friction, the hydraulic pumping pressure and flow rate for the stage can be calculated. A numerical solver is required.

The simulation software makes some key assumptions.

1. An average true vertical depth (TVD, ft) and frac gradient (psi/ft) for the lateral is used for every stage on a well. In reality, these can vary depending on, e.g., how toe-up or -down the lateral is.
2. For a given stage, while sand is being pumped, the average perf hole diameter and Cd is held constant. This is the average of all clusters across all points of time of the stage. This results in the perforation friction being fixed to the average value for that stage the entire time sand is being pumped.
3. It is further assumed that the average perf hole diameter and Cd for a stage is unaffected by the number of clusters per stage (i.e., if perf designs would, in practice, actually vary per cluster, those designs would be adjusted accordingly when adding a cluster to maintain the prior average perf diameter).
4. Similarly, a single value of tortuosity pressure loss is used. In reality this value is highly variable, including through an individual stage (e.g., because of the gradual smoothing of the fracture paths).
5. Because this approach varies stage lengths, one must choose a consistent way of handling the fact that, for a given target completed lateral length (i.e., a target gross perforated interval) and stage length, there is not an integer number of stages. I.e., if the target lateral length is 10,000ft and stage length is 225ft, there would be 44.444… stages. This paper assumes one will always round up to the next integer number of stages (e.g., in the prior example, 45 stages and a 10,125-ft lateral). This can cause some slight imprecision when comparing scenarios because, if one wants to compare to 275-ft stages, the algorithm will round up to 37 stages and a 10,175-ft lateral. So, comparing the, e.g., total cycle time and/or completion cost per well will not be perfectly "apples-to-apples". This slight imprecision was deemed acceptable, and, to assist, normalized KPI's such as "lateral length per day" and "cost per foot" will also be compared.
6. Regardless of the stage length, the average proppant concentration of the stage is the same. I.e., regardless of stage lengths in a fixed lateral length, the amount of water per unit length placed in the lateral is identical. I.e., although, for longer stage lengths, there will be fewer flushes, the proppant ramp rates will be adjusted to maintain a fixed amount of water for the well. If this assumption was removed, such that proppant ramp rates are constant per stage regardless of stage length, any potential cost and time savings would increase due to fewer pumping minutes performing flushes, etc.
7. Changing the number of stages per lateral could potentially have cycle time and cost impacts on phases other than the frac phase (e.g., varying number of plugs in the same lateral length could slightly change cleanout phase cycle times). These changes are assumed to be negligible, and the cycle time and cost comparisons will focus on the frac phase (the phase from start of fracing the first stage on pad to the end of fracing the last stage on pad).

Several of the physics-based inputs are difficult to precisely know. Nonetheless, historical use of the physics models with typical values used as inputs has evidenced reliable predictions of average flow rates per stage. Figure 1 shows a lookback of three Devon wells comparing

- the average per stage flowrate predictions of their in-house modeling tool prior to PrePad,
- PrePad's average per stage flow rate predictions, and
- the measured average flow rate per stage for three wells.

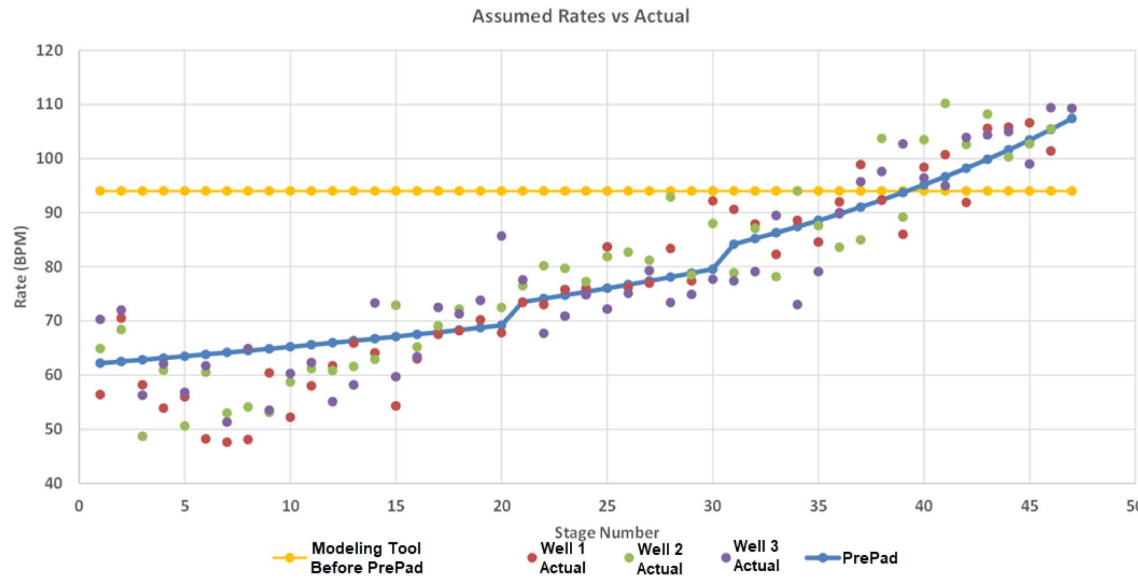

Figure 1—Avg Flow Rate Per Stage Comparison Between In-House Modeling Tool, PrePad, and Well Actuals

Such results increase confidence that the novel software's incorporation of the first-principle physics drastically improves the per-stage estimate accuracy and precision.

Approach/Procedure

A typical, representative base scenario was selected. This is a representative scenario that accounts for design requirements, contract models, a given operational efficiency, etc. that would be standard for a given area and formation in which the wells are landed. The cycle time and cost savings benefits of the final optimized design will be compared to this base scenario.

The simulation software is used to predict execution, logistics, cycle time, and total cost for every scenario. This includes predicting the flow rate at each stage which, in most scenarios, can be increased throughout the lateral as less pipe friction has to be overcome. The base design includes a minimum flow rate per cluster, so, with the predicted flow rates, the maximum number of possible clusters per stage can be estimated. Because adding a cluster to the stage will change the achievable flow rate, the algorithm needs to be applied in an iterative fashion. In each iteration, no more than one additional cluster is added to any stage.

An example version of the algorithm is outlined in Figure 2.

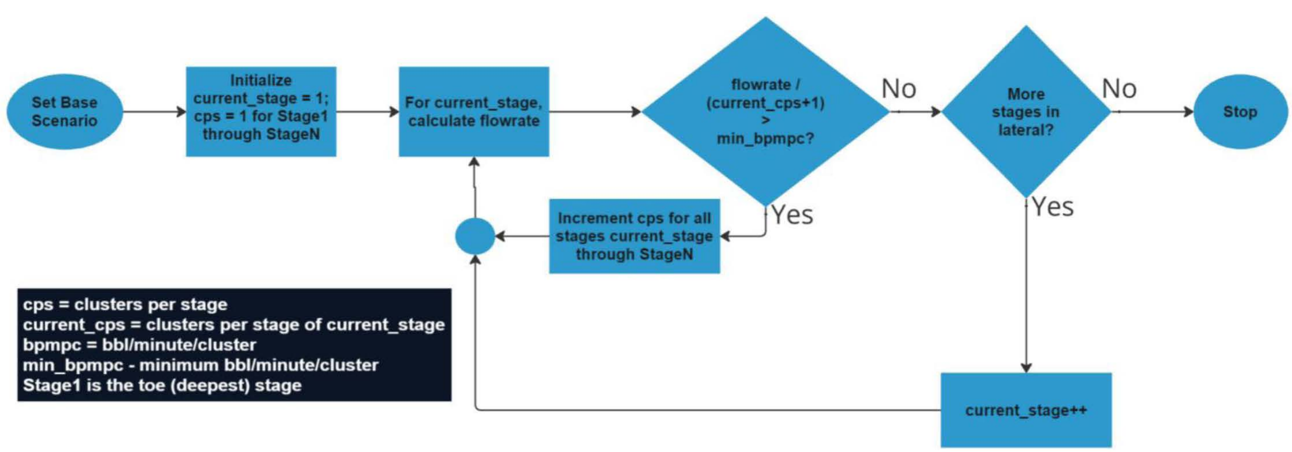

Figure 2—An algorithm for dynamically adding clusters to stages throughout a lateral

In this case study, because the simulation is so fast and does far more than predict when to add additional clusters, the flow rates and possible clusters per stage are calculated for every well stage. Only the stage design for the deepest stage will be adjusted before moving on to the next iteration.

The details of the process simulation and cost calculations are beyond the scope of this work. For this standard non-simul frac, plug-and-perforate scenario, the process simulation will execute a zipper frac operation. Cycle time, pumping times, and consumables are predicted. Combined with the base designs and precise contractual assumptions, costs are calculated per line item and phase (e.g. Prep, MOB, Frac, Cleanout). Absolute and normalized costs will be calculated. Within a single scenario, total costs will be normalized by lateral length and, when relevant to show, individual cost line items or buckets will be shown as a percentage of that scenario's total cost. Absolute values will not be shared due to the sensitive nature of such cost information. Subsequent scenarios (scenarios that are iterations in the optimization process) will have their cost and time benefits documented as percentages of the base scenario.

Two primary KPI's are used for each scenario: average lateral length completed per day (ft/day) and completion cost per unit length ($/ft). The primary reason is because of the assumption that, while trying to keep the lateral length for each scenario as close as possible, lateral lengths will be rounded to an integer number of stages. For the iterations in this case study, this resulted in lateral lengths as short as 10,025ft and as long as 10,190ft. This is an almost 2% difference in lateral length. To remain within design constraints, this results in a 2% difference in total sand, water, etc. placed in the well. Normalizing by lateral length keeps the cycle time and cost comparison as fair as possible.

Some key inputs held constant across the scenarios include the maximum stage average pumping treating pressure and flow rate (that an operator and service provider are willing to go up to and hold). The physics algorithm uses these as targets and constraints. For this scenario, these values are assumed to be 11,000 PSI and 125 bbl/min. The amount the fluid system reduces pressure due to friction (K_{red}) and the pressure loss due to tortuosity (P_{tort}) are assumed to be within ranges of industry standards.

Base Scenario

Base Design and Strategy

Reviewing the base scenario will also give an overview of what the simulation software is accounting for to inform decisions and quantify benefits. The base design, a four-well pad based in the Delaware Basin, is meant to be one typical for the basin—not a documentation of any specific Devon design. The following are screenshots from the software showing the specified inputs.

The wells are landed in 3rd Bones Spring Sand where every stage is assumed to have a true vertical depth of 10,900 ft and a frac gradient of 0.83 PSI/ft. The target lateral length for each well is 10,000ft.

Figure 3 provides an overview of the base stage design requirements. For the base scenario, every stage in the lateral has this design.

The sand-to-water ratio of 1.4 with a sand loading of 3000 lb/ft results in a water loading of a little more than 51 bbl/ft. This design is partially based on the expected flow rate on some of the stages. If targeting no less than 8 bbl/min per cluster, and one expects to pump approximately 95 bbl/min, no more than 11 clusters per stage can be used.

Because the target lateral length is 10,000ft, the base stage length is 165ft, and the assumption to round up to an integer number of stages, the actual simulated base lateral length is 10,150ft.

The perforation design and assumptions regarding discharge coefficient and cluster efficiency are also key inputs. The specifics are not shown for privacy concerns. They are held constant for all stages in all scenarios and are instrumental in the physics calculations, especially the perforation friction.

An approximate wellbore diagram is provided in Figure 4. The most important fact regarding the casing, other than the approximate measured depth, is the internal diameter. The production casing is 5.5-inch, 20 ft/lb, P-110 which has an internal diameter of 4.78 inches.

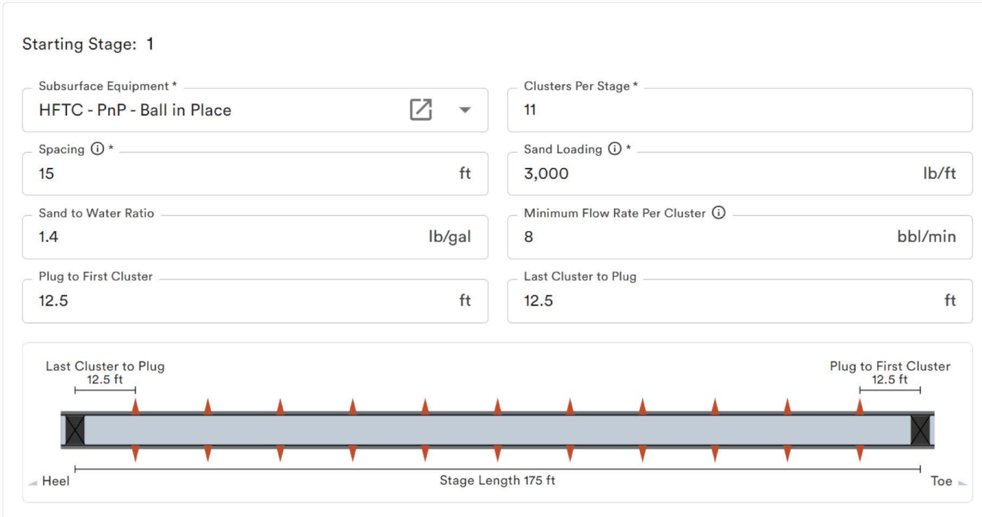

Figure 3—Base Stage Design Requirements (Inputs set in PrePad software)

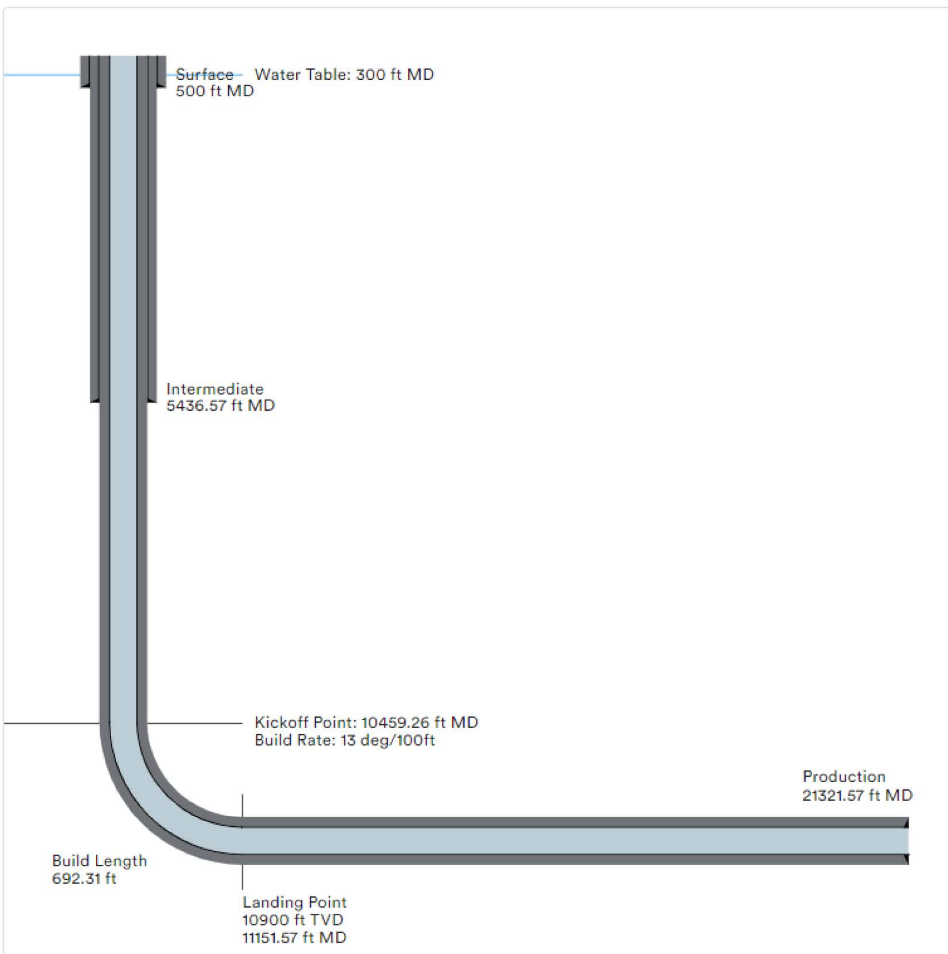

Figure 4—Approximate Wellbore Diagram

Frac spread type (Tier II diesel Tier II/Tier IV Dual Fuel electric), fuel costs, frac method (zipper vs simulfrac operations), contract details, operational efficiencies are all incorporated as inputs. The details of it and other service providers' contracts, operational efficiencies, etc. cannot be shared. Nonetheless, they are held constant across all scenarios, so results are somewhat independent of these details. Most exceptions would be contracts that are not at all compatible with varying anything about stage design throughout a lateral (e.g., a pumping services contract that charged a fixed price per stage).

Base Results. Details of the base scenario's simulation will be documented to provide insight into what is being accounted for in the optimization process.

The cycle time estimate is the result of a discrete event simulation that, among other things, determines an optimal frac order. Figure 5 shows the intra-pad Gannt chart which shows the high-level activities taking place on each well during each minute of execution.

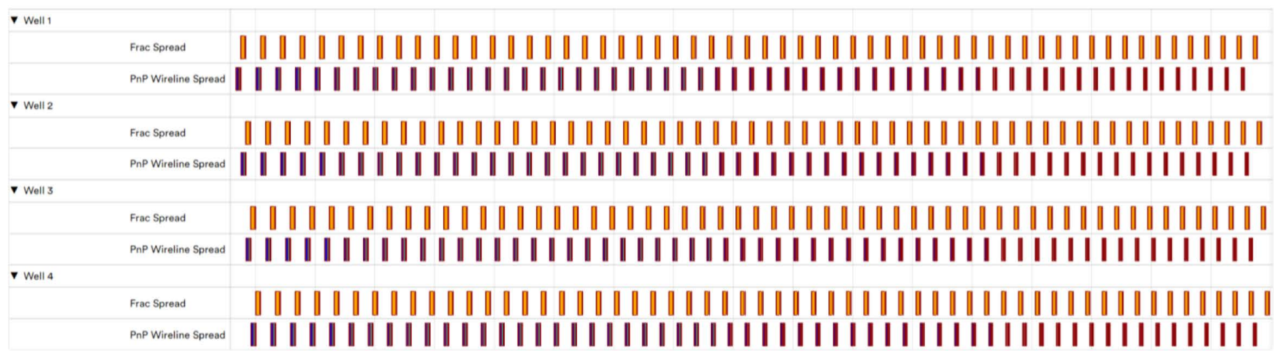

Figure 5—Process Simulation Results (timestamps removed)

Figure 6 shows a zoomed-in view to highlight details of the process simulation. One can see the zipper operation. I.e., one can see the wireline/pumpdown activities occurring on one well while fracing is occurring on another.

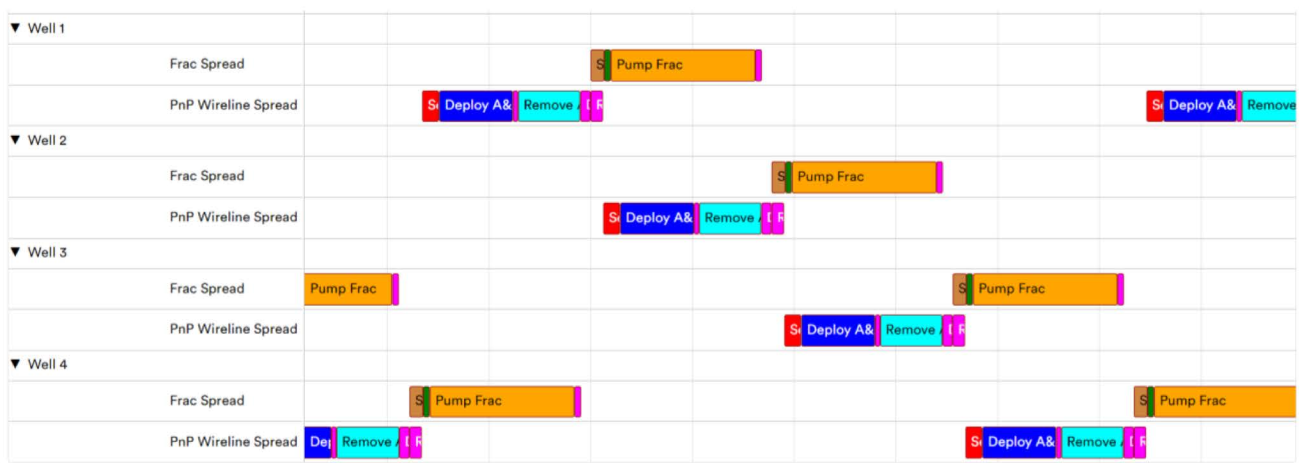

Figure 6—Process Simulation Results (timestamps removed) (zoomed-in)

The most critical activity in the process simulation is the "Pump Frac" activity. This captures "pumps on" to "pumps off" for the stage. This pumping time is a result of the stage design and achievable hydraulic pumping flow rate at that stage. Figure 7 shows plots displaying four key values per stage: the total water, the total slurry volume (volume of water and sand), the average hydraulic slurry flow rate, and the resulting pumping time per stage.

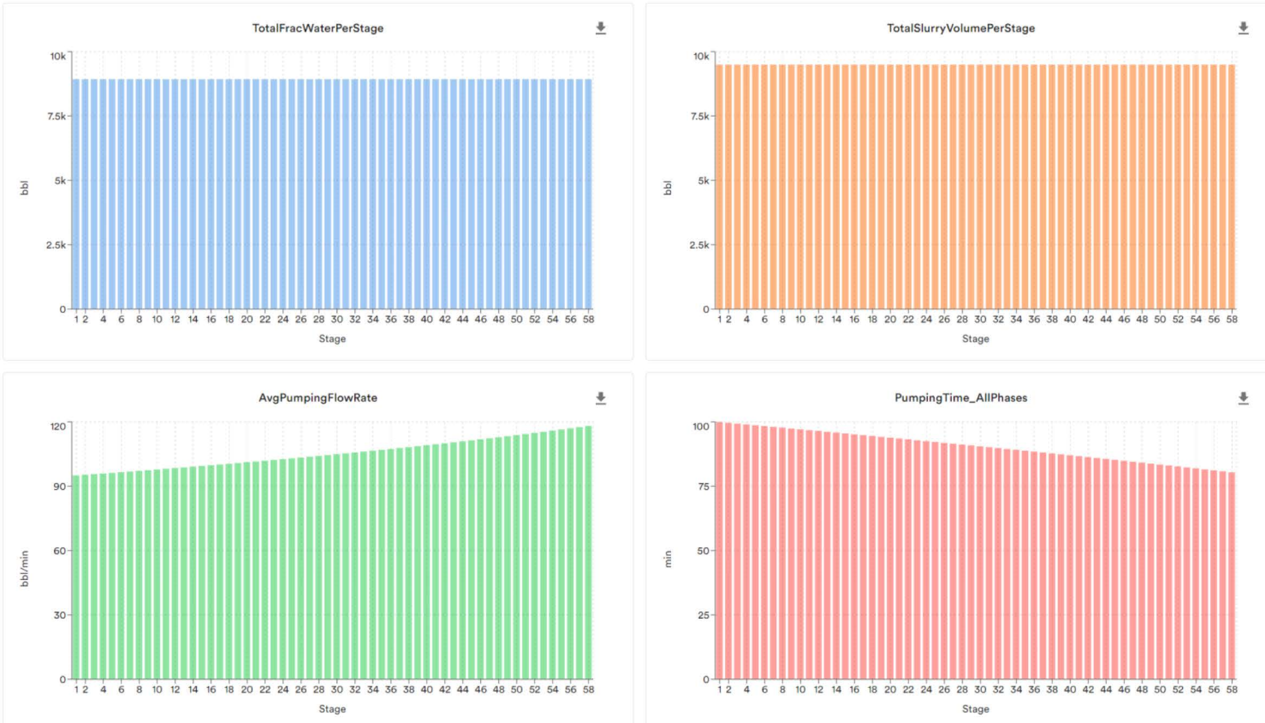

Figure 7—Base Scenario: Key values dictating pumping time per stage

The achievable flow rate is determined per stage using the physics equations previously described (Figure 8).

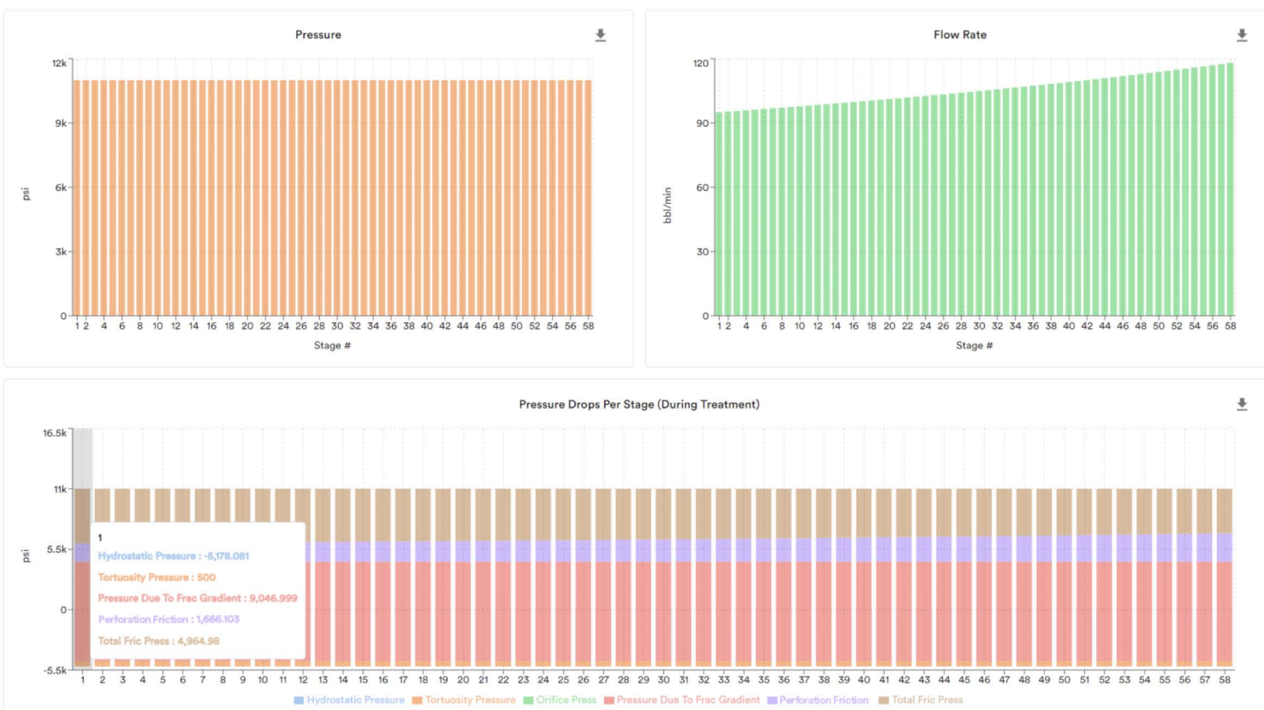

Figure 8—Avg. Per Stage Hydraulic Pumping Pressures and Flow rates

Finally, combing the above with all consumables and contracts, the costs are calculated for each phase for as many line items for which one wants to account. In this case study, over eighty contractual items are incorporated. The cost line items are functions of one of the following:

- $/pad,
- $/well,
- $/unit-lat.-length,
- $/day,
- $/stage,
- $/cluster,
- $/unit-sand,
- $/unit-water,
- $/unit-diesel, or
- $/unit-NG.

The cost estimator also incorporates detailed frac contracts. These can include one or more of the following:

- active pumping costs ($/pumping-hour or $/pumping-minute),
- standby charges ($/standby-hour),
- day rate ($/day),
- fixed stage charge ($/stage),
- NPT penalty/credits, and/or
- price escalations for stack-frac'ed stages (%).

It further accounts for the fact that the $/pumping-hour charge can vary based on the one of the following:

- individual stages' average pumping pressure and/or flow rate,
- individual stages' treatment (with sand) pumping pressure and/or flow rate,
- individual stages' max pumping pressure and/or flow rates, or
- the max pumping pressure and/or flowrate experienced during the pad.

The above is documented to make clear the level of precision in the simulated cost. The total Frac Phase costs are combined into a single $/ft number. That number is used to make relative comparisons to the optimized design.

Further, the execution speed throughout the completion process is normalized to a single, average lateral length per day (ft/day). This one value will be used in the comparison, but the software can show the varying speed as progress is made uphole (Figure 9).

Figure 9—Base Scenario: Execution Speed Throughout Frac Phase

Example Process & Results

With the base scenario defined, the dynamic stage length algorithm can be executed. In this case study, each iteration is run individually so the impact of each change can be seen.

In this example scenario, asset development constrains the minimum flow rate per cluster to be 8 bbl/min/cluster. The base design meets this requirement on the first stage (88.6 bbl/min / 8 clusters = 11.1 bbl/min/cluster > 10 bbl/min/cluster). However, the flow rates continue to increase significantly through the lateral possibly allowing for additional clusters while still meeting the asset development requirement.

Starting with the base scenario (Iteration 0) and each subsequent iteration, the software is used to find the first stage at which a cluster could be added. A new design will be made where that stage and all shallower will have the additional cluster. This will be repeated until no more clusters can be added on any stage. The normalized execution speed and costs will be calculated for each iteration and shown at the end.

Iteration 0

The base stage design is shown again in Figure 10. In this iteration, every stage in the lateral has this design.

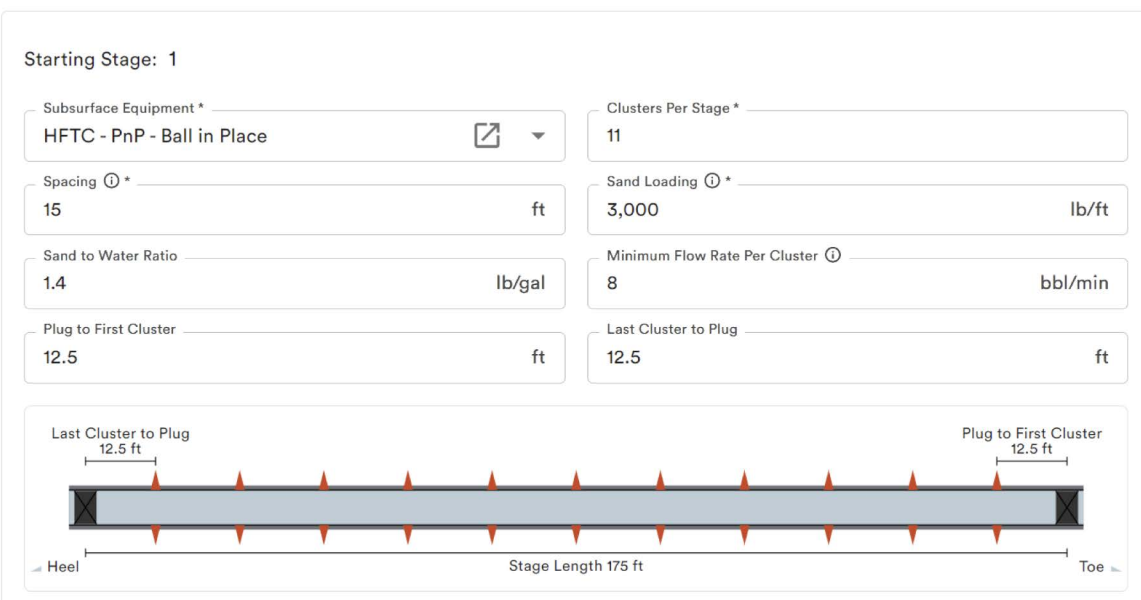

Figure 10—Iteration 0 (Base Scenario) Stage Design (Stage 1 to Heel)

Figure 11 shows, for each well stage, the predicted slurry flow rates per cluster, perforation friction, possible clusters per stage, and how many additional clusters over the current design are possible. This final estimate is only precise for the deepest stage because, if an additional cluster is added at it and subsequent stages, stage counts and physics calculations change. For each iteration, only this deepest stage calculation will be utilized. This shows a new cluster can be added on Stage 5 where the bbl/min is surpassing 96 bbl/min (8 bbl/min/cluster * 12 clusters = 96 bbl/min).

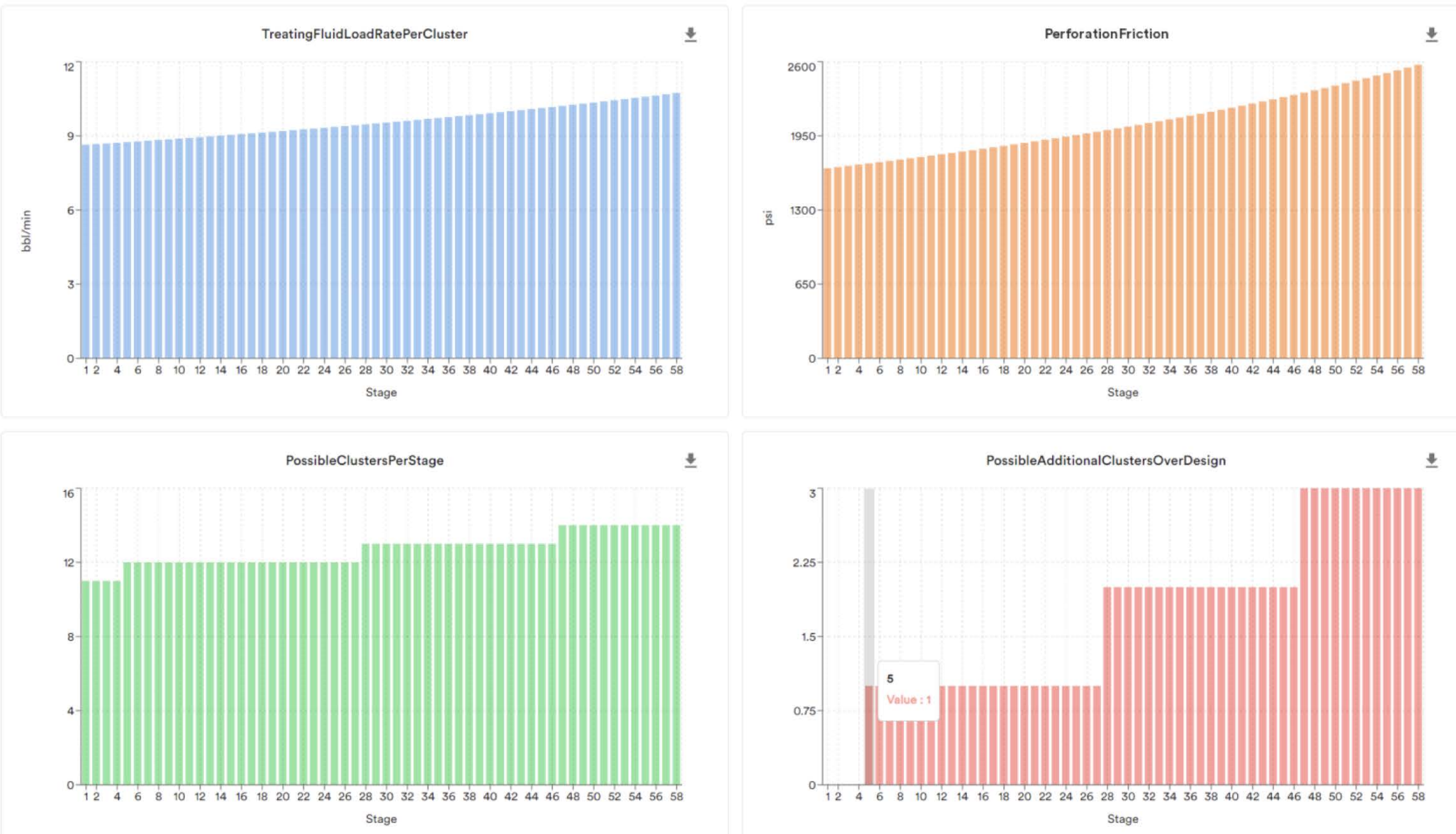

Figure 11—Iteration 0 (Base Scenario): Flow rate per cluster estimating adding cluster on Stage 5

Iteration 1

The new stage designs include the one from Iteration 0 and the one shown in Figure 12 with the key differences highlighted. Note that, once the stage length was increased, the additional stage could actually be added on Stage 4 (slightly different access area per stage and slight rounding in lateral lengths leads to different measured depths).

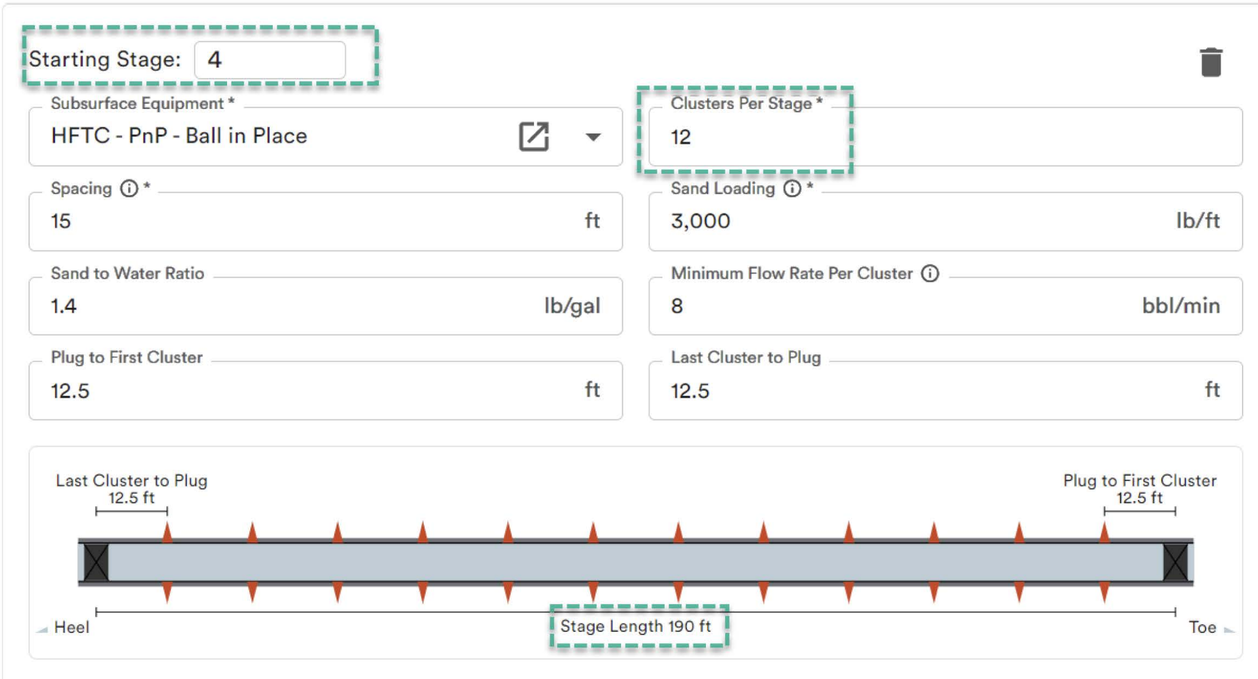

Figure 12—Iteration 1's Additional Stage Design (Stage 4 to Heel)

Simulating again shows a prediction that minimum rate per cluster is met on all stages and an additional cluster can be added on Stage 20 (Figure 13).

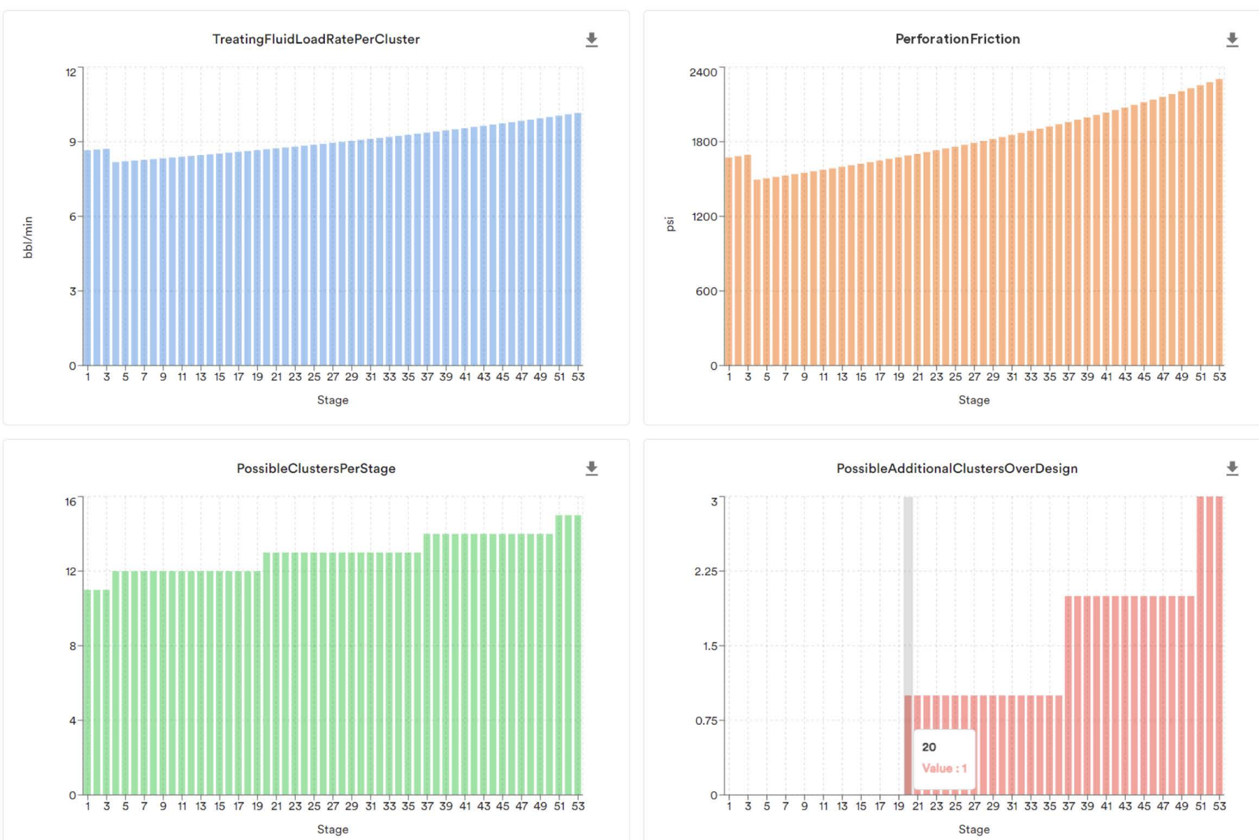

Figure 13—Iteration 1: Flow rate per cluster estimating adding cluster on Stage 20

Iteration 2

The new stage designs for Iteration 2 include the two from Iteration 1 and the additional one shown in Figure 14.

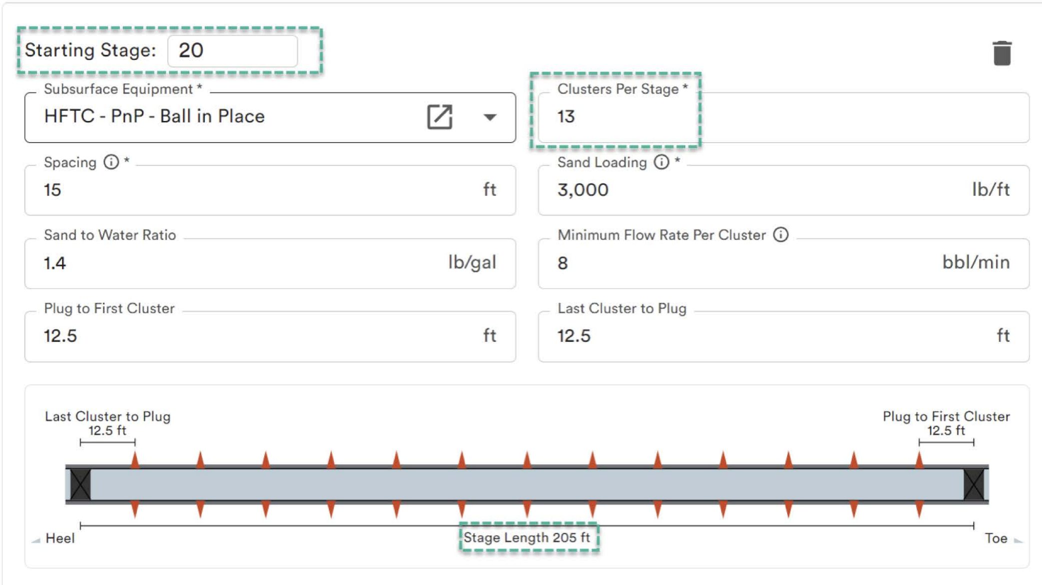

Figure 14—Iteration 2's Additional Stage Design (Stage 20 to Heel)

Simulating again shows the minimum flow rate per cluster is met and an additional cluster could be added on stage 32 (Figure 15).

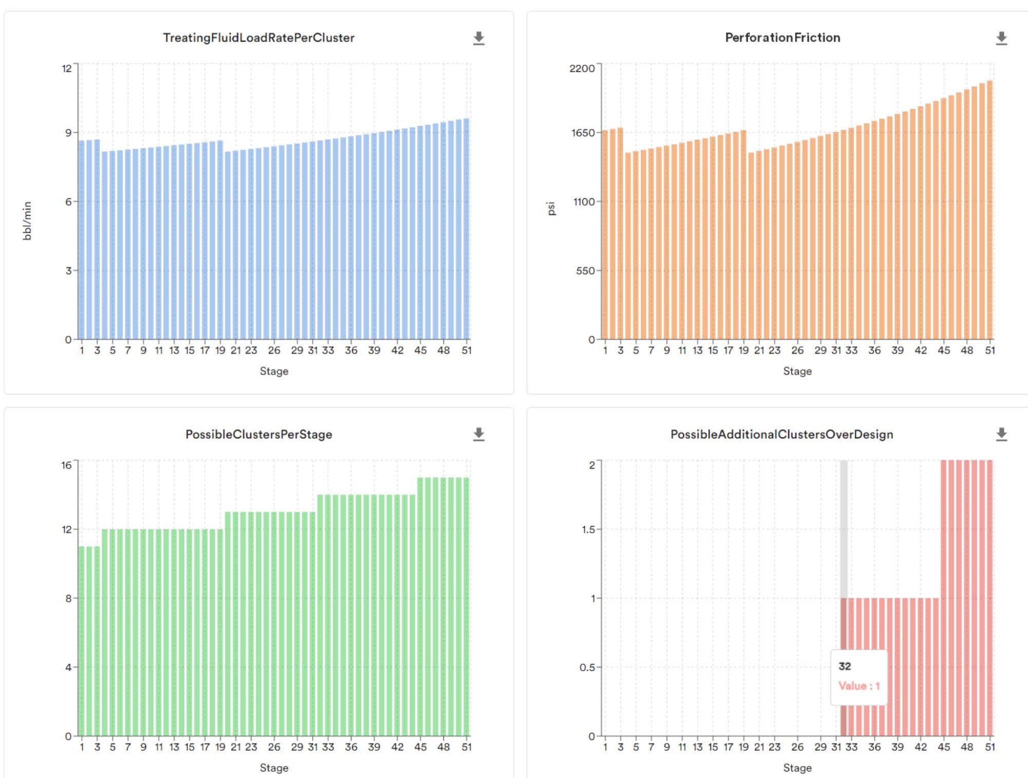

Figure 15—Iteration 2: Flow rate per cluster estimating adding cluster on Stage 32

Iteration 3

The new stage designs for Iteration 3 include the three from Iteration 2 and the new one shown in Figure 16.

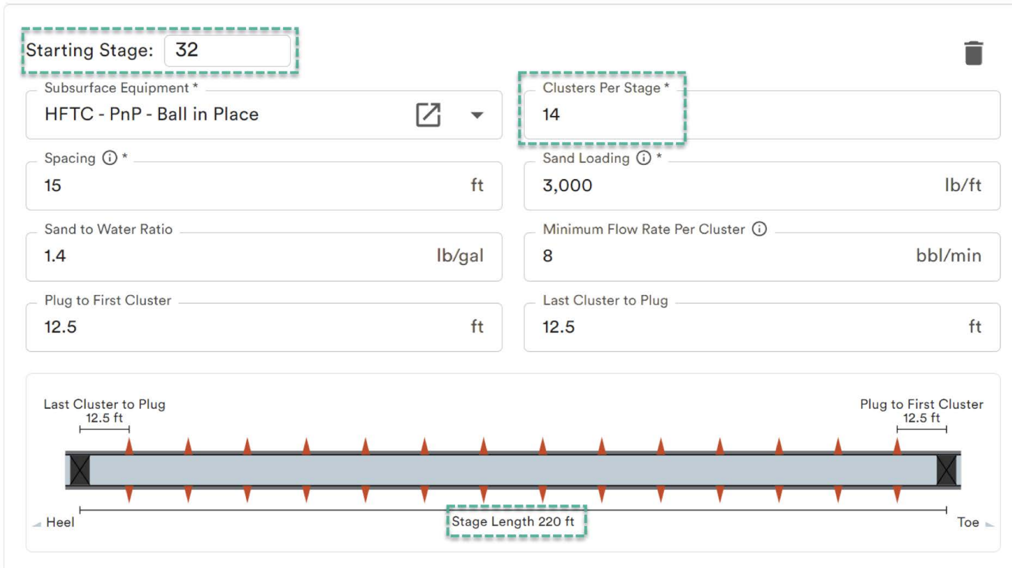

Figure 16—Iteration 3 (Final Design)'s Additional Stage Design (Stage 40 to Heel)

Simulating again shows the minimum flow rate per cluster is met and an additional cluster could be added on stage 41 (Figure 17).

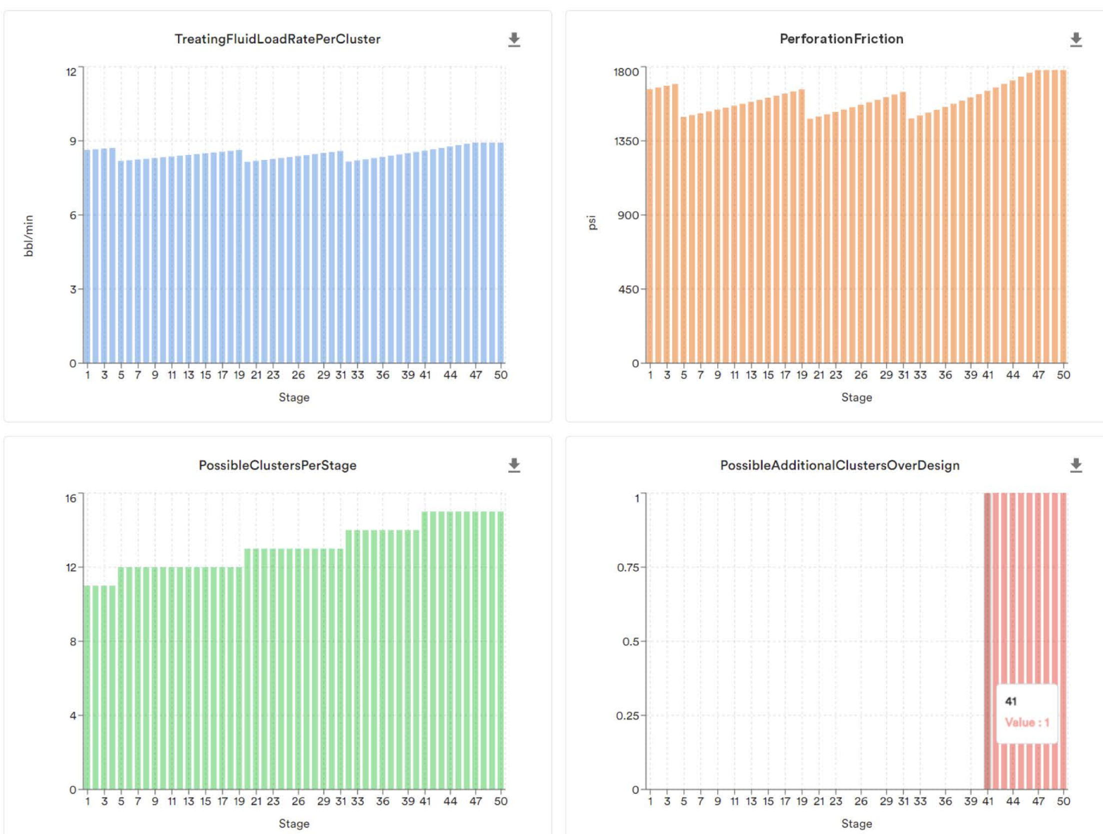

Figure 17—Iteration 3: Flow rate per cluster estimating adding cluster on Stage 41

Iteration 4

The new stage designs for Iteration 4 include the four from Iteration 4 and the new one shown in Figure 18.

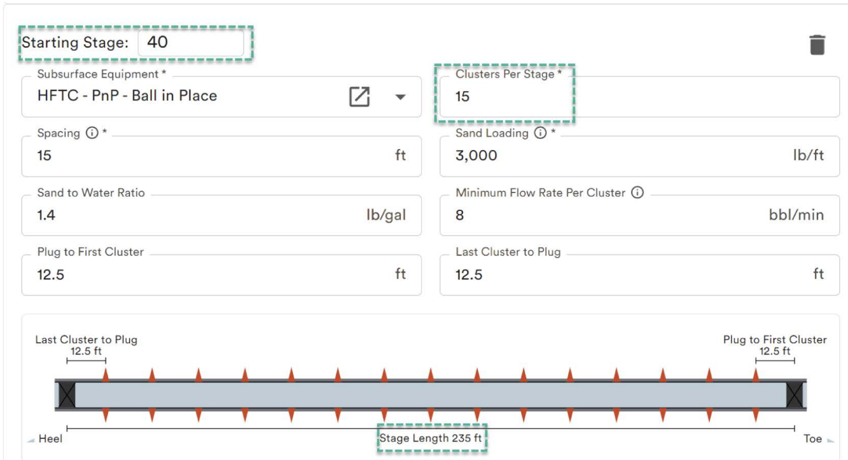

Figure 18—Iteration 4's (the final optimized design's) additional stage design from Stage 40 to heel

In this iteration, the software predicts that no stages could take another cluster. This is the final iteration.

For this final iteration it is prudent to show that some of the other critical design values have been maintained. Figure 19 shows the adjustment to stage length resulting in corresponding changes in water and sand per stage and that the minimum flow rate per cluster is never violated (the lowest value is 8.129 bbl/min/cluster). Figure 20 shows the values critical to pumping duration (the same shown for the base design).

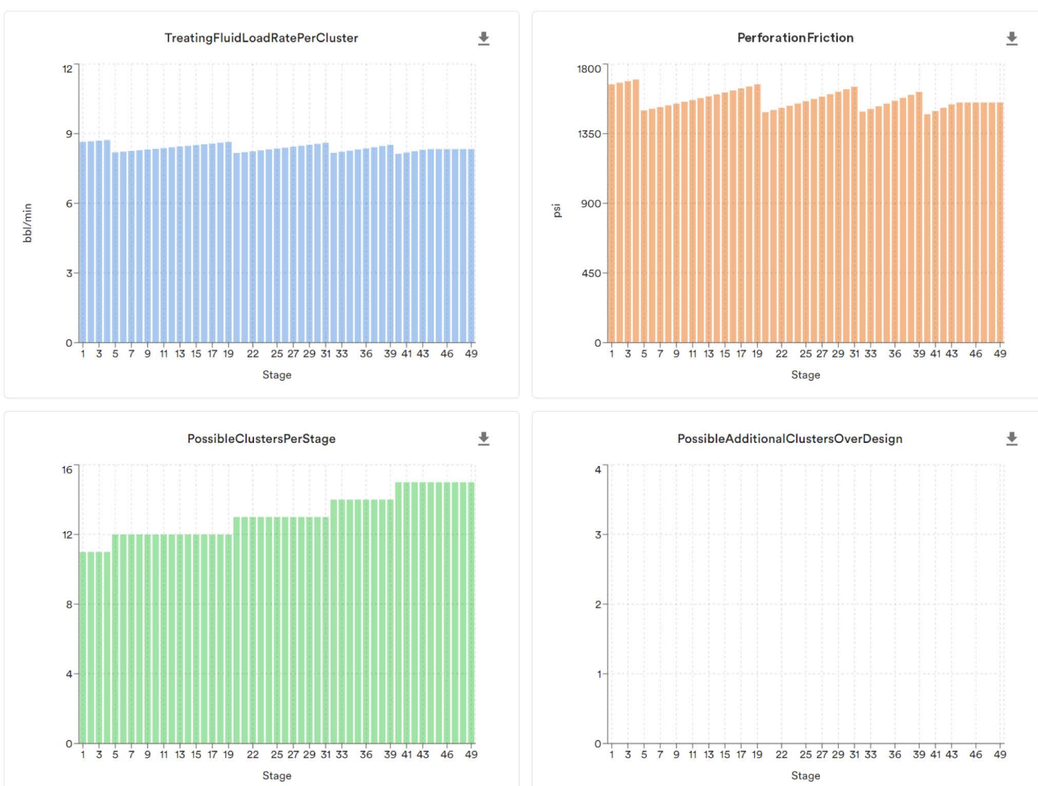

Figure 19—Iteration 4 (Final Optimized Design) Flow rate per cluster showing no more stages can be added

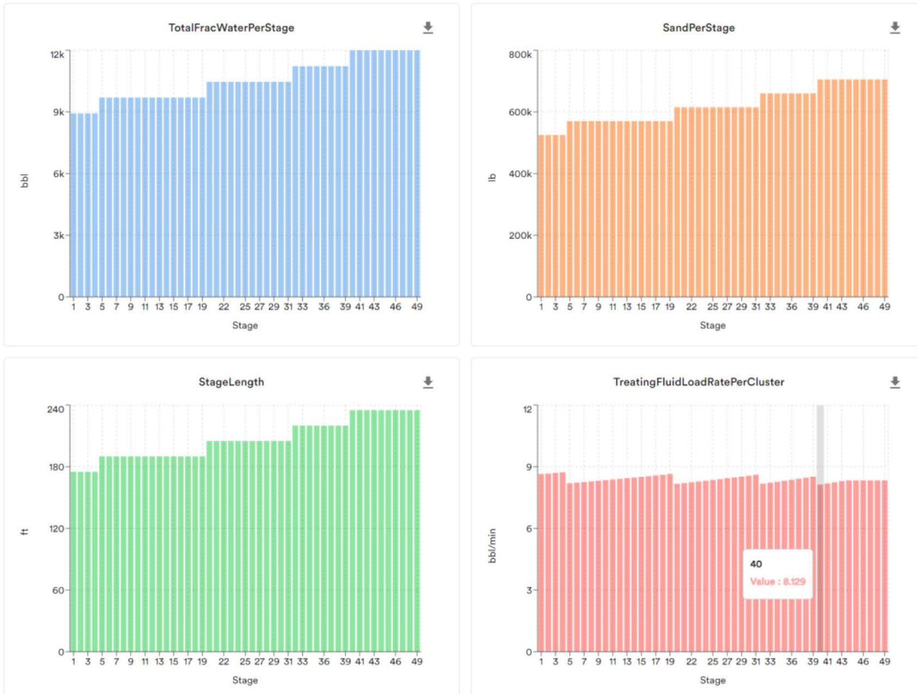

Figure 20—Final Design's Values Key to Asset Development Constraints

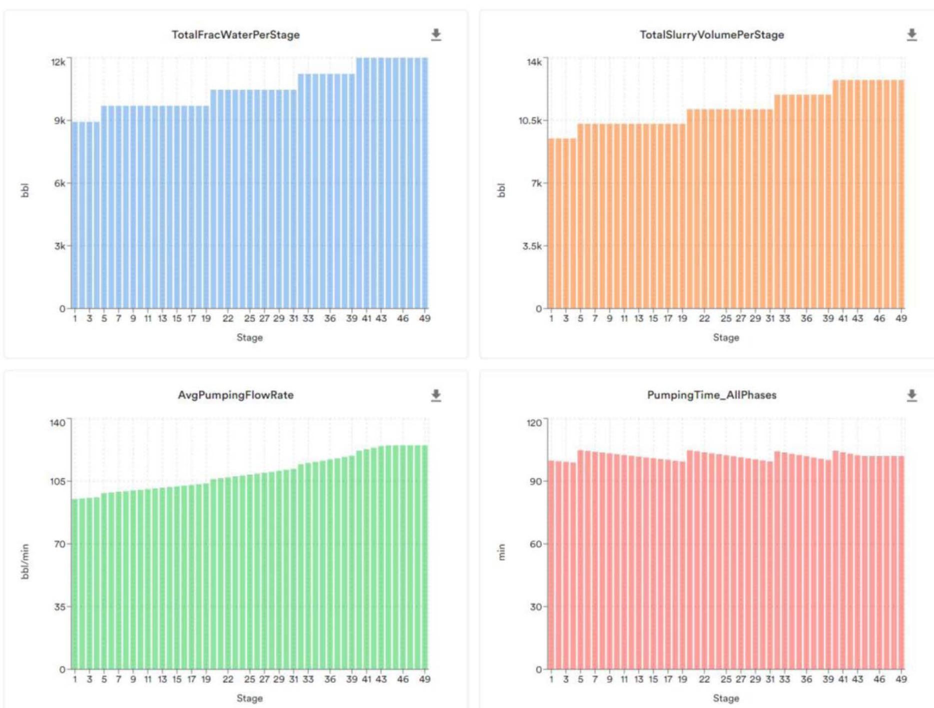

Figure 21—Final Design's Values Key To Pumping Duration

Value Summary

Figure 22 and Figure 23 show the increase in execution speed and cost savings relative to the base scenario (Iteration 0). The final design (Iteration #4) shows an almost 6.3% increase in ft/day and more than 2.1% decrease in cost. Hypothetically, if the base case four-well pad had a total pad frac phase cycle time of 20-days, four wells could come online 1.25 days sooner (assuming cleanout, production, facilities, etc. crews are available to shift forward correspondingly). If the base case per well frac phase cost was $3MM per well, adjusting the number of clusters per stage dynamically could save over $60,000 per well. These benefits come per well while adhering to asset development design constraints. And, with the help of commercial software, these optimizations can be performed in under five minutes.

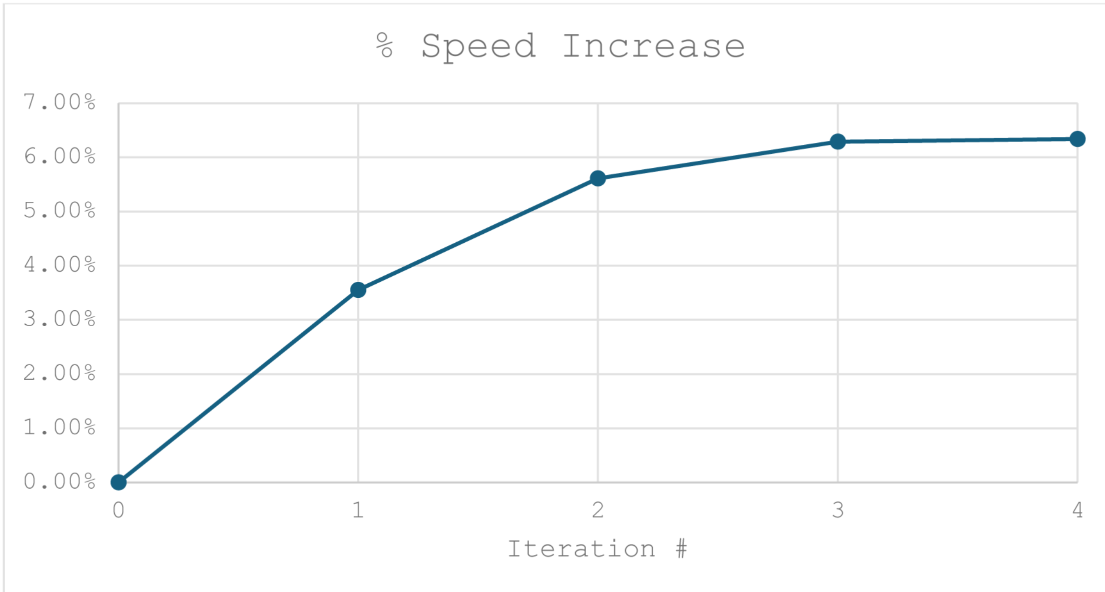

Figure 22—Increased Execution Speed of Each Iterative Scenario (Relative to Base)

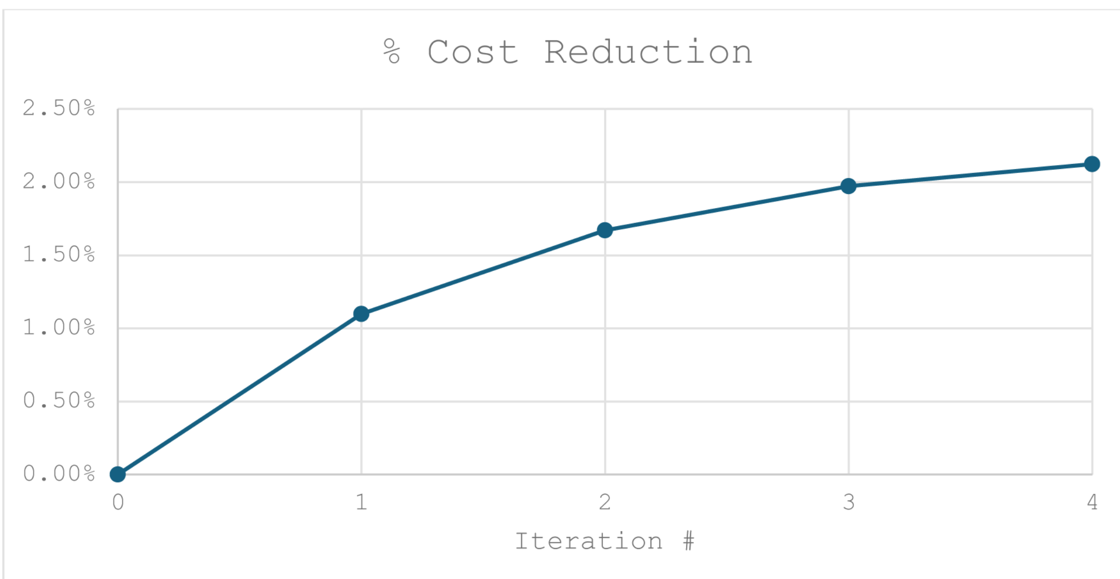

Figure 23—Increased Cost Savings of Each Iterative Scenario (Relative to Base)

Figure 24 shows the cost line items that had the largest impact on the cost reductions. These are largely due to reduced cycle time, stage count, and pumping hours. The reduction in pumping hours is due to the increased number of clusters per stage, reducing perforation friction and allowing a higher total flow rate.

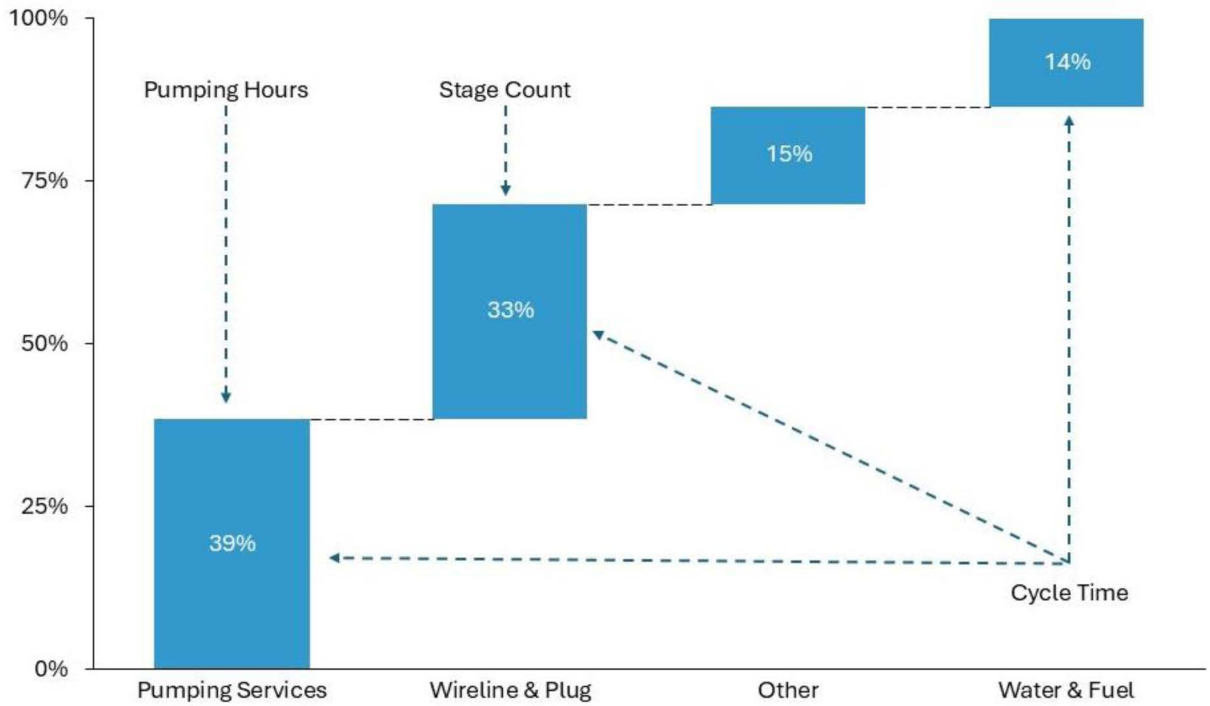

Figure 24—Cost groups most responsible for cost savings

These quantitative benefits are consistent with those seen by Devon: upper five-figure savings per well and four-well pads being brought online faster.

Moving to dynamic stage lengths also increases the consistency of how stages are treated from the toe to the heel. By allowing flow rate to be maximized without any other changes results in perforation friction gradually increasing from toe to heel (see equation in Definitions and Assumptions section). Adding an additional cluster will decrease the perforation friction of the stage, allowing for the mentioned increase in rate. This behavior was observable in the iterations shown above. The final average perforation friction per stage for Iteration 0 (the base scenario) and Iteration 4 (the final optimized design) are shown in Figure 25. The final design has a far more consistent (far lower standard deviation) than the base scenario.

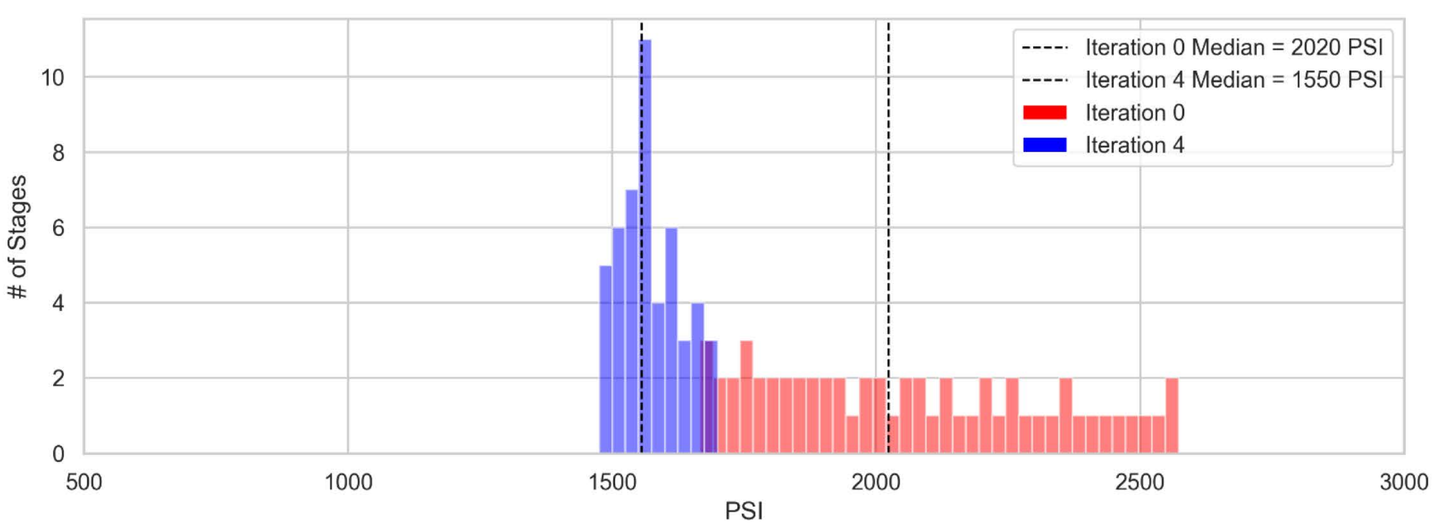

Figure 25—Perforation Friction Per Stage for Iteration 0 (fixed stage length) versus Iteration 4 (optimized, dynamic stage lengths)

Other Practical Considerations

There are additional considerations to achieve a more seamless transition between design and execution when evaluating a dynamic stage length within a program. Thorough pre-job planning is required such as equipment and material supply chain capabilities (e.g., increased lubricator length to rig up to account for increased length of gun string, sand & water volume demand variability through a lateral). A maximum stage length could also be driven by design needs, infrastructure capabilities, or rate capabilities of a fleet which would need to be considered as part of the model constructed. Additionally, maintaining operational flexibility is important as there could be variances compared to what was captured in the model (e.g., market trends, pricing changes, DUC counts, reservoir heterogeneity). An alternative approach might be needed to maintain design parameters pending what those variances are and overall impact.

Summary/Conclusion

This paper has documented a workflow for gradually increasing stage length from a lateral's toe to its heel while maintaining asset development design constraints (and, therefore, presumably not creating any risk to well performance). Doing so has qualitative benefits such as reducing risk (fewer wireline runs for a given lateral length) and increasing treatment consistency across a lateral (with far more consistent perforation friction across the lateral). The quantitative benefits range from reduced cycle time (from, e.g., fewer stage transitions) and reduced capital expense (from, e.g., fewer frac plugs). This case study's representative scenario showed a 6.3% reduction in cycle time and 2.3% reduction in capital expense from a workflow that, because of highly suitable simulation software, is performed in under five minutes for any given pad. A 2.3% completion cost reduction across a 100-well program where the per-well completions cost average is $3MM is a savings of over $6MM. Far higher saving potentials are possible if slight water loading reductions are permitted.

Applying dynamic stage lengths is one example of how execution optimization can add further value to the industry and how suitable simulation software enables workflows to unlock and quantify it. Future work will include documenting other execution-optimization workflows: e.g., casing design selection, single- versus simul- versus trimul-frac operations, pumping service provider contract configuration, etc. The dynamic stage length analysis could be extended to explore sensitivities under other circumstances. For example, this case study assumed a 5.5-inch monobore casing design. Utilization of liners or tapered strings can have even more flowrate variability from toe to heel potentially leading to more substantial results. In general, such detailed cycle time and cost estimating can be integrated with wider asset development considerations (e.g., well performance and economics) to assess the full value of production acceleration.

This work's primary importance is in showing one example of execution optimization (adjusting designs, strategies, etc. unlikely to have impact on well performance) on top of asset development optimization (adjusting design, strategies, etc. integral to well performance). Historically, oil and gas operators have adopted planning software specializing in the latter. Many execution-optimization opportunities are often neglected due to operations-focused engineers' job demands and lack of software with sufficient execution elements to quantify differences in scenarios. Devon's recent adoption of PrePad™ (software that includes fluid dynamic physics simulation of hydraulic fracturing, discrete-event simulation of the completion process, and detailed contractual modeling) has enabled their operations-focused engineers to perform high granularity execution optimizations such as designing dynamic stage lengths.

While the precise results will vary between designs and contractual circumstances, any operator equipped with highly granular cycle time and cost models could replicate a similar workflow and realize similar benefits.

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