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Reducing Emissions in Hydraulic Fracturing for Geothermal Application with the Technology Revolution

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ABSTRACT

Geothermal energy harnessing requires hydraulic fracturing to enhance and sustain required energy output per well. When hydraulic stimulation is considered for such systems, the surface emission print of a geothermal system may be significant. Classically, the hydraulic fracturing system consists of a high number of powerful pumps connected to deliver the required flow rate at a given pressure. Currently, most of the pumps used in such applications are driven by diesel engines which will result in a high CO2 and other emissions footprint during the fracturing process.

A previous paper presented at Stanford Geothermal Workshop has pointed out that emissions, especially CO2 emissions, during geothermal well construction are the highest during a geothermal project lifetime.

This paper discusses first the current hydraulic fracturing emissions using a case study as an example which includes a possible CO2 tax (as an example of Norway). We also address how emissions can be reduced using conventional fracking units and where the limitations are.

In the second part of the paper we talk about the novel technologies available which imply partial or full electric fracking units, and how such systems could revolutionize the geothermal through major emission reduction and better job quality.

1. INTRODUCTION

A large amount of the time and energy spent to acquire reservoir parameters that are used in building reservoir models for simulations can be used equally as much for completion designs. Hydraulic fracturing requires careful planning to understand the behavior of the reservoir rock and surrounding rock so that proper fracturing parameters can be identified and set. The hydraulic fracture decreases the skin of the wellbore-reservoir contact by increasing the surface area contacts through the creation of fractures. To maintain this contact area, it is critical to deliver the correct size and amount of proppant to the reservoir. Similarly, because of the necessity of fluid to apply the pressure needed to break the formation and to carry the proppant, we must also carefully design for an appropriate fracturing fluid. Once the proper fracturing slurry has been created, we must determine the hydraulic horsepower necessary to deliver the pressure and flow rate needed to fracture and deliver proppant to the reservoir. This hydraulic horsepower is delivered by a series of diesel frac pumps. Because of the nature of the machines, it is inevitable that these aforementioned pumps will see breakdowns. In the case that pump contingency is not considered, these breakdowns can cause significant non-productive time (NPT). As a result, pump breakdowns not only incur repair costs, but also lost producing time due to delayed stimulation. Indubitably, the proper maintenance and implementation of frac pumps is a critical design element of a successful fracturing plan. Moreover, stricter environmental regulations across the globe have required more efficient use of our engines. Where we once only considered the cost of NPT, we must now also consider the economic burden brought upon by emission taxes and engine emission compliance. Our paper seeks to optimize the use of a frac pump in a case study well with respect to both NPT and emissions. In the second part of the paper we discuss about the novel technologies out there which implies partial or full electric fracking units, and how such systems could revolutionize the geothermal through major emission reduction and better job quality.

McCay et al. (2019) have shown that the CO2 emissions for deep geothermal wells are the highest during the well construction phase which includes drilling rig operation and reservoir development. Figure 1 shows their emission within three life cycles of a deep geothermal well. Figure 2 shows a compilation of various costs per ton of CO2 of various countries as of 2018. Currently, electric driven drilling rigs are a reality, with a new trend in using current power grid especially when geothermal wells are located near cities or in the vicinity of available electric power. The next step is the ability to reduce emissions during hydraulic fracturing of geothermal wells. Hydraulic fracturing has been shown to be an inevitable step in creating efficient and long-lasting geothermal resources. Although alternative technologies to fracturing may exists, it has been found that hydraulic fracturing has the highest potential to unlock geothermal resources when applied carefully.

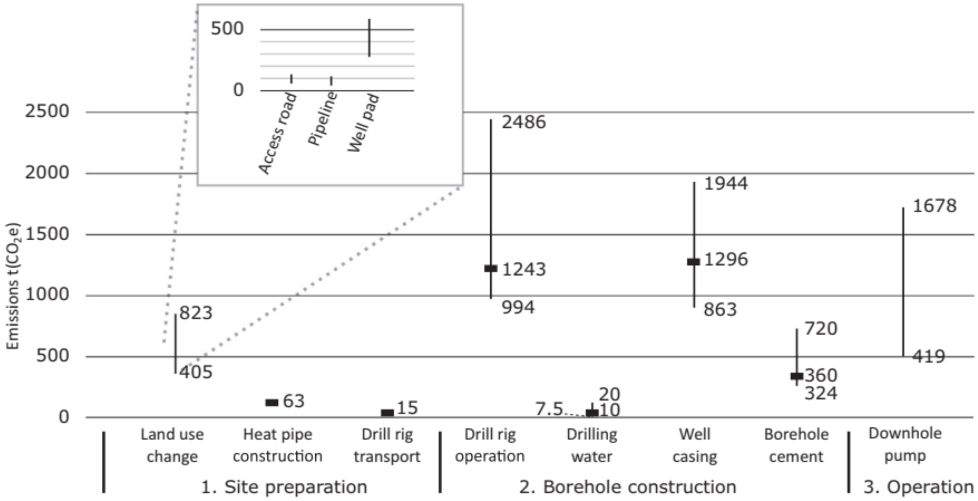

Figure 1 - CO2 emissions of a deep geothermal well (McCay et al., 2019)

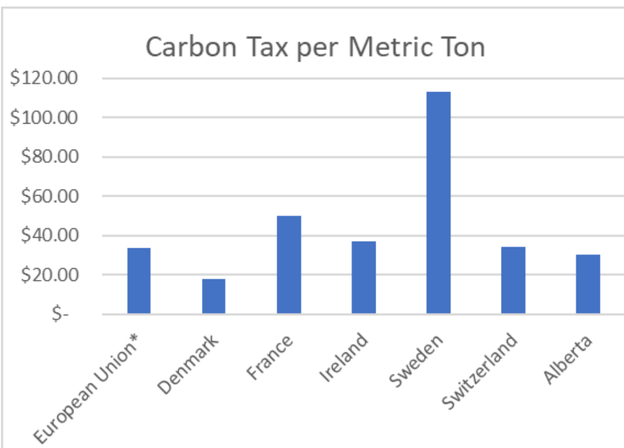

Figure 2 – Carbon taxes in various countries (sources vary) *recommended value

2. HYDRAULIC FRACTURING PROCESS ANALYSIS

To understand the emissions during the hydraulic fracturing process, the following sections show the estimation of such emissions using as example a synthetic case of a fracturing job used for an unconventional well. Since geothermal well fracturing data is relatively small, we decided to use the unconventional well as an example, since our focus is mostly related to the type of fracturing fluid and amount pumped rather than geothermal reservoir properties.

2.1 The Fracking Process as Emitter

The service companies that provide completion services to their clientele design their own pumps but outsource their engines to companies such as Caterpillar and Cummins. These engine manufacturers provide many engine capacities for different operations. Because of this specificity, no two engines act entirely the same when used in different applications. For example, an offshore diesel engine is far more regulated by environmental organizations than an equivalent onshore engine. This results in a different emissions profile than an equivalently powered land engine. This regulation structure may go above and beyond design criteria by imposing taxes on or regulation of emissions with differing intensities. Examples of carbon taxes are shown in Figure 2. The EPA does strictly regulate the emissions on offshore engines but does not always regulate small engines used on rig sites. As a result of these regulations, emission data is far more prevalent for offshore engines than onshore engines. The emissions of these engines are slightly cleaner than their onshore equivalents but can be used as a close analogue. For the countries that charge for emissions, frac plans must use engines as efficiently as possible. Minimizing the NPT of a pump will in turn reduce the emissions; engines are often left running between stages to avoid the complications of start-up and shut-down. Knowledge of each engine's emissions allows us to better implement them into a plan that is optimized with respect to emissions and NPT.

According to the US Energy Information Administration, the costs related to fracturing in unconventional wells can be broken down into the categories mentioned below (JWN 2016).

1) Rig Related Costs

The factors that affect the rig related costs in unconventional wells include:

- Efficiency of drilling
- Target depth
- Rig days rate
- Mud costs
- Diesel fuel rates

Rig related costs can be anywhere within the range of $0.9 million to $1.3 million, which make up from 12 to 19% of an unconventional well's total costs.

2) Casing Costs

Casing costs are an important factor to be considered in the economic design of unconventional wells. The factors that affect the casing costs include:

- Casing prices and markets
- Steel prices
- Dimensions of the well
- Formation pressures

The casing costs can vary as the well depths and dimensions vary within formations. Also, several different casing strings might need to be used. The casing costs can generally range between $0.6 million to $1.2 million and make up anywhere from 9 to 15% of the total well costs.

3) Frack Pumping Costs

The pumping costs for fracturing jobs can be highly variable and depend of several factors which include:

- Type of fuel used
- Horsepower needed
- Number of frack stages or hours of operation

The horsepower in turn depends on the formation pressures, rock hardness or brittleness index, maximum injection rate. The total pumping costs for all stages can range anywhere from $1 million to $2 million. The pumping costs show most variation than any other type of costs and can range from 14 to 41% of the total well costs.

4) Completion Fluid Costs

The completion fluid cost is a major component in the economic design of a fracturing project. The cost is mainly governed by the amount of water used and the type of chemicals mixed with it. The main frack fluid types include gel, cross linked gel and slick water. Gel based fluids are primarily used in oil formations while slick water in gas formations. There are also disposal costs associated with the completion fluids, as around 20 to 30 percent of the frack fluid flows back from the well after it's brought online for production. Typically, operators consider the disposal costs for the first month or two of flow back to be included in the CAPEX. The overall completion fluid related costs can range anywhere from $0.3 million to $1.2 million and make up for 5 to 19% of the total well cost.

5) Proppant Costs

The proppant costs can vary by the amount and type of proppant used in the completions. More proppant is used by operators when going for cheaper options like sand compared to artificial or high strength alternatives. The amount of proppant used in general is increasing in all the plays as well. The cost of proppant can range anywhere between $0.8 million and $1.8 million and make up 6-25% of the total well costs.

2.2 Pump Operation Cost

The goal of a fracture pumping operation is that the added ultimate production as a result of fracturing the well will be more profitable than the cost of pumping equipment and materials. In order to optimize a fracture plan with respect to NPT and emissions, we must look at the associated costs of the fracture pumps. The biggest operation costs for a pump are diesel cost, crew/repair costs, and in certain countries, emissions costs. To compare these costs, we have used data from a Caterpillar C280-6 in various counts that provide a cumulative 15,288hp. These engines behave differently with respect to fuel consumption and emissions amount at 100%, 75%, and 50% loads. While the relationships shown by the Caterpillar C280-6 may not identically match every engine consumption/emissions profile, this does help us understand trends. For example, based on Figure 3, there is a decline in diesel cost per hour at 100% load, which is the result of more efficient combustion. Even though 100% load is more efficient, many operators will run pumps at 50% load vs. 100% load in hopes to reduce breakdown frequency. This also allows the pump operator to share the load of a broken-down pump if a breakdown occurs mid-stage. If contingency is desired, it is still possible to have pumps running at 100% but have a few 0% load pumps in the manifold to take over in case of breakdown. There is a 9% diesel cost savings by running at 100% vs. 50%. Many countries are trying to incentivize emissions reduction by imposing various taxes on CO2 and NOX. Figure 4 depicts the range of emission taxes that could be imposed in these countries for the same case proposed by Figure 3. There is a 7% decrease in costs by running at 100% load vs. 50% and 75% load.

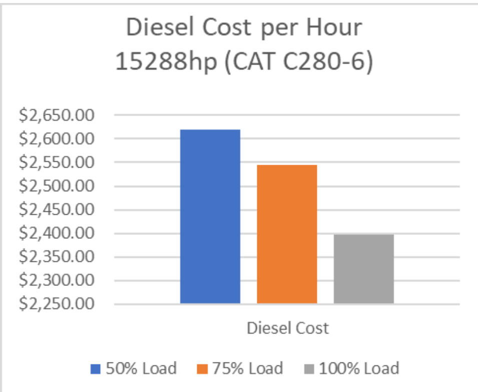

Figure 3 - Diesel costs of a set case of Caterpillar engines

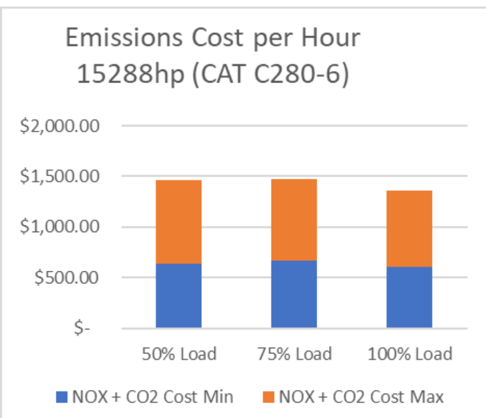

Figure 4 - Potential emissions taxes of a set case of Caterpillar engines

The non-productive time for pumping operations needs to be minimized for proper efficiency of the fracturing operations. We also found out that NPT is also directly related to emissions, since an engine that runs at maximum capacity may often require maintenance when compared with other scenarios. There are many components in the system where the failure could occur, adding to the costs and the non-productive time. For a fracturing job, the flow path starts at the hydraulic pumping trucks which supply the fluid volumes and the required pressure to fracture the rock. The high-pressure fluids then flow through the manifold, whose purpose is to combine the flow from multiple trucks into one line. The fluids then move into the frack tree and then towards the target formation. A secondary manifold that connects to the frack tree may sometimes be used. All these components have multiple connection points and failure may occur anywhere. The major failure mechanisms include the following (please note that some of these mechanisms may not directly apply to geothermal):

Erosion: Erosion happens when solid particles impacting a metal surface at a high velocity remove the material from it.

Loss of Actuation: The proper actuation and operation of valves is crucial to any frack job. During frack operations, the valves encounter a significant amount of solid particles such as sand which can accumulate in the valve cavity and cause the valve not to operate properly.

Mechanical Wear: There are a lot of moving parts involved in the whole fracturing process, including the valves that open and close multiple times during the operations and at each fracture stage, which adds to mechanical wear and tear of the parts.

Valve Failure in Frack Tree: The failure of valves in the frack tree has a huge impact on the overall operational efficiency. The frack valves are essential components and the last line of defense when it comes to maintaining well control. In case of valve failures, the operations are shut down for maintenance. Additional valves may need to be purchased, adding to the costs.

All the failure mechanisms need to be considered thoroughly while designing a frack job and the non-productive time should be calculated, low and consistent in order to maintain the operational efficiency of fracturing jobs. Ultimately, the goal is to properly design the jobs for lower operating costs, efficient use of the capital invested and safety of operations. Next, the costs of pumping operations and repairs are discussed. The fuel consumption and economics of alternative fuels have also been presented.

The maintenance costs for pumping are usually related to valve failures or failures due to erosion/corrosion. In case of unexpected failures due to design miscalculations, the costs can rise. A solution can be to deploy additional pump units as backup to reduce the chances of non-productive time but the inherent risk in the rest of the flow path, including the manifold and the permanently installed frack tree at the well head, still exists. Any failure in the flow path will result in downtime and resultantly in disproportionate costs.

The schematic of a typical frack tree and the configuration of valves are shown in Figure 5. In case of a valve failure, the actual costs often turn out to be more than what has been calculated for repairs. Usually, a valve repair is expected to take eight hours using a $2,500 ticket, but the actual costs can go up to $14,500 per hour for a fracturing spread, which estimates to a total of $116,000 for the whole eight hours. In addition to the costs, the whole operation also goes on hold during repairs resulting in non-productive time which eventually translates into loss of revenue.

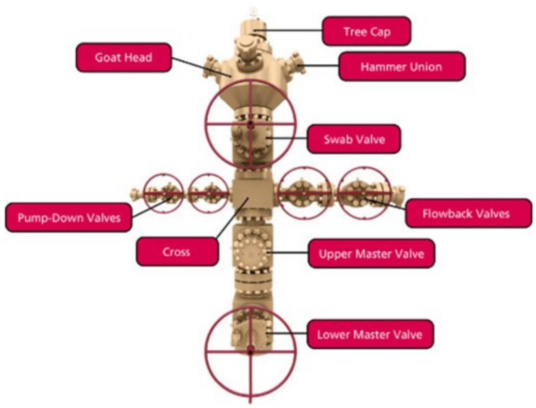

Figure 5 - Typical configuration of a frack tree demonstrating the flow path (Pitcher 2015)

The operating costs for pumping operations can reach an average cost of $250,000 and possible valve repair services are initially estimated at $2,500. These costs estimates are optimistic as there can be costs for consultants, trailers, light plants, cranes, wireline, well control, water transfer crews, trash crews, man lifts, forklifts, and downhole services that bring the estimates to more than $100,000 per day. In case the frack tree needs any repairs due to design flaws, costs up to $350,000 can be added to the expenses. In case of a more serious issue, the failure could result in a shutdown of up to a week and the resulting cost can range anywhere between $0.7 million to more than $2.4 million.

3. FRAC JOB MODELING AND RESULTS

A design is needed as a base to create a case for a fracture stimulation job with optimized reduction of NPT and emissions. For this purpose, using an offset well used in unconventional production, a design was created for three scenarios of fluid use: slick water, linear gel, and crosslinked gel. Although the well used for this case study is not a geothermal well, the workflow used herein can be extrapolated for any geothermal applications that will require multistage fracturing.

The model chosen is the two-dimensional PKN-C (Perkins and Kern with Carter Equation 2 for fluid loss) as described by Rahman M. M. and Rahman M. K. (2010). This model was chosen because it has been shown to produce more accurate fracture length predictions according to three-dimensional models than other one-dimensional or two-dimensional models (Rahman 2010). The PKN model is a one-dimensional model for fracture geometry meaning that it models fluid flow in only one direction (Economides 1995). The PKN-C model is considered a two-dimensional model because it models fluid flow in two directions. It models fluid flow along the long axis of the fracture as well as into the walls of the fracture (Economides 2000). Being that the model chosen is not three-dimensional, there are several limitations to consider in conjunction with the results for the fracture stimulation design. The model does not account for vertical fluid flow. The model does not account for multiple heterogeneous layers. The model requires the assumption of a single homogenous layer with fracture height assumed to be contained and approximately equal to the vertical thickness of the formation.

One fracture design is created for each fluid type. Primary inputs for the fracture design based on the PKN-C model include formation moduli and Poisson's ratio, fluid rheology, proppant characteristics and desired geometry. Geometry, proppant selection, and formation characteristics are held constant amongst the designs in order to observe the changes in pump operational requirements based on fluid type. In this case, height is selected as 200 ft based on core and log data contained in literature concerning the Cana Woodford in the area of interest (Caldwell 2013). Fracture length is targeted at 1,000 ft. Width is variable although similar at approximately 0.19 inches for linear and crosslinked gel. Each design consists of four transverse bi-wing fractures with each half fracture geometry being in accordance with previous listed values. Fluid rheology as well as leak-off coefficients are chosen and assumed based on literature values (Callanan (1985), Settari (1985)). Values for formation moduli and Poisson's ratio are taken from literature sources (Hia et al. 2017).

Another important factor in the design specifically affecting the pumping requirements was the closure pressure of the formation. This pressure was determined from log analysis to be about 6300 psi. The rheology of the different fluid types combined with the length of lateral, hydrostatic pressure based on fracture slurry density and the closure pressure of the formation all combined to determine the treatment pressure required for each fluid type. The operating conditions predicted by the model for each design are shown in Table 1. Despite the fracture geometries being kept the same, other than width, each fluid type requires different operating conditions. These rates and pressures will be the limiting factors for pump selection. Tables 2, 3, and 4 display the possible pump number requirements based on the operating conditions produced by the model. With the current designs emphasizing a comparison of pumping requirements based upon similar geometry for each fluid case, despite differences in fluid both linear and slick water have similar requirements in pumping time. However, to complete the equivalent job, crosslinked gel requires two to three times the pumping time of either linear gel or slick water and will be expected to cause more wear.

Table 1 - Operating conditions for each designed fracture stimulation including max treatment pressure, max treatment rate, hydraulic horsepower, and stage time.

Fluid Type	Max Treatment Pressure (psi)	Max Treatment Rate (bbl/min)	Hydraulic Horsepower (hhp)	Stage Time (hr:min)
Crosslinked Gel	16855	32	13216	2:49
Linear Gel	2574	48	3028	0:52
Slick Water	4215	72	7436	1:26

Table 2 - Number of pumps necessary based on operating conditions for crosslinked gel scenario (Halliburton Energy Services 1997).

Crosslinked Gel				
Gear: 8.6:1				
Operating Condition	HHP (hhp)	% Operating Pressure	Pumps Required	10% Contingency
Intermittent < 4hr	577	100	23	26
Intermediate 4 to 8 hr	375	75	36	40
Continuous	264	50	51	57
Gear: 8.4:1				
Intermittent < 4hr	768	100	18	20
Intermediate 4 to 8 hr	500	75	27	30
Continuous	352	50	38	42
Continuous	352	50	22	25

Table 3 - Number of pumps necessary based on operating conditions for linear gel scenario (Halliburton Energy Services 1997).

Linear Gel				
Gear: 8.6:1				
Operating Condition	HHP (hhp)	% Operating Pressure	Pumps Required	10% Contingency
Intermittent < 4hr	577	100	6	7
Intermediate 4 to 8 hr	375	75	9	10
Continuous	264	50	12	14

Gear: 8.4:1				
Intermittent < 4hr	**768**	**100**	**4**	**5**
Intermediate 4 to 8 hr	**500**	**75**	**7**	**8**
Continuous	**352**	**50**	**9**	**10**

Table 4 - Number of pumps necessary based on operating conditions for slick water scenario (Halliburton Energy Services 1997).

Slick water				
Gear: 8.6:1				
Operating Condition	**HHP (hhp)**	**% Operating Pressure**	**Pumps Required**	**10% Contingency**
Intermittent < 4hr	**577**	**100**	**13**	**15**
Intermediate 4 to 8 hr	**375**	**75**	**20**	**22**
Continuous	**264**	**50**	**29**	**32**
Gear: 8.4:1				
Intermittent < 4hr	**768**	**100**	**10**	**11**
Intermediate 4 to 8 hr	**500**	**75**	**15**	**17**

4. OPTIMIZATION OF EMISSIONS AND NPT

It was decided early to examine fluid type as a potential design decision in the optimization of NPT and emissions because of the extreme affect that changes to fracturing fluid may have on pumping requirements. This variety of pump requirements is shown in Table 1. In addition to changing fluid type, two different pump maintenance scheduling methods were also selected. In one method, pumps would be run until a part broke requiring maintenance. In the other method, preventative maintenance would take place between stages with a stage not proceeding until all expected preventative maintenance was completed. Lastly, two different methods for pump engine management were selected. In one method, engines would be kept idling between stages to eliminate start-up and shut-down times. In the other method pumps would be shut off between stages to save on emissions. The combination of different fluid type, engine management, and pump maintenance schedule yields twelve different scenarios to test.

To test the twelve scenarios for the case of most optimized NPT and emissions, a model of a fracture stimulation job's pumps was required. The job model would keep track of each pump's operating time, idling time, and part or maintenance requirement status. Maintenance requirements would be based on the during-job 10hr, 100hr, and 200hr recommendations as described earlier. Parts and tasks being tracked included the worm gear, bypass valve, suction/discharge valves, magnetic oil strainer/filter, oil change, and diesel flush. Five random sets of starting pump operating times were generated using random number generators. Maintenance was assumed to have followed the manual perfectly with parts replaced at the previous encountered 10hr, 100hr, or 200hr time leading up to the starting time. Using random number generators and weighting factors, each part or task would role a chance at failure during each stage. The chance for a part to fail would increase at slow rate before the suggested maintenance times. As more stages were run, leading to more time being added to the part, the chance would increase. The chance to fail would then start to increase at a greater rate after the expected maintenance time was encountered. Eventually, if a part ran for more than double the suggested maintenance period, it would have a near 100 percent chance at failure.

If the role indicated that the part failed, it would have to be replaced between stages. As this job is a single and not a zippered well, the amount of time available to perform repairs without incurring NPT would be based upon the amount of time needed to shoot the next stage of perforations and land a frac plug. This time was calculated based on Weatherford reported speed for their wireline conveyed frac plug of 500 feet per minute (Weatherford 2015). The total time allotted would be based upon the measured depth of the next stage and an added 45 minutes for making up guns, stabbing on the lubricator, shooting perforations, landing a plug, and removing the guns and lubricator. Crew available to work was calculated based upon capstone group remembers limited exposure on site to fracture jobs. Pumps would then be repaired in an order of operations minimizing repair time based upon number of pumps needing repair, crew available, and repairs needed of each pump. Additionally, 10 minutes were added for pressure testing any time a repair was required. Start up and shut down times were also added based on only the number of pumps repaired in the pumps idling case and based on the total number of pumps for the “pump shutdown” case. NPT would then be calculated based on time exceeding the allotted repair time between stages. Idle time as well as number of pumps idling was also recorded.

In the case of preventative maintenance, repairs or maintenance would be performed if a part failed before expected maintenance time, or if the pumping time of the next stage would cause a part to exceed its suggested maintenance time. A total of 150,000 iterations of the model were made spread evenly amongst the twelve scenarios with 30,000 for each randomly generated set of starting times. NPT amongst the twelve scenarios is described in Table 5. Emissions as described by cost are shown for the twelve scenarios in Table 6.

Table 5 - NPT non-productive time by stage for slick water, linear gel, and crosslinked gel using four scenarios of preventive maintenance with and without idling and no preventive maintenance with and without idling.

Fluid Type	NPT, Idle (min)	NPT Idle w/ Prevention (min)	No Idle (min)	No Idle w/ Prevention (min)
Slick Water	21	27	28	33
Linear Gel	11	12	13	14
Crosslinked Gel	37	62	48	71

Upon examination, NPT is least for the linear gel case followed by slick water and crosslinked gel, respectively. In addition to this, across all fluid types with both idling and non-idling scenarios, the case with preventative maintenance has greater NPT. Keeping the fluid and maintenance program the same, the idling scenario has less NPT. It is unsurprising that linear gel, with the fewest pumps required to meet its HHP needs, has the least NPT overall. It is also unsurprising that the idling engines case has less NPT than the not idling case, as the non-idling case must deal with additional start up and shut down times for all the pumps and engines. Preventative maintenance having greater NPT can be explained as well, though it may be counterintuitive at first glance. By running a pump to its failure point, it will need to be repaired less frequently than a pump being repaired exactly according to a fixed schedule, given that the schedule has a high design factor resulting in early repairs. It may be possible with a more optimistic schedule to obtain longer times between repairs, resulting in a preventative maintenance plan with less NPT. Though currently, the plan utilizing the maximum time a part can survive is the best plan. Therefore, amongst all available options that should produce near equivalent geometries, when optimizing for NPT, the best-case scenario is the linear gel fluid fracture stimulation design, with a non-preventative maintenance schedule and the pumps idling between stages, to present an average NPT per stage of 11 minutes across the 20 stages job.

Table 6 - Cost of emissions by stage for slick water, linear gel, and crosslinked gel in both a total and per pump basis with minimums and maximums.

Slick Water	Total Time running (min)	Total Emissions Cost Minimum	Total Emissions Cost Max	Pump Unit Cost Minimum	Pump Unit Cost Max
Idle	109	$533.92	$1,203.16	$41.07	$92.55
Idle w/ Prevention	108	$527.38	$1,188.43	$40.57	$91.42
No Idle	86	$420.66	$947.94	$32.36	$72.92
No Idle w/ Prevention	86	$420.66	$947.94	$32.36	$72.92
Linear Gel	**Total Time running (min)**	**Total Emissions Cost Minimum**	**Total Emissions Cost Max**	**Pump Unit Cost Minimum**	**Pump Unit Cost Max**
Idle	74	$146.82	$330.84	$24.47	$55.14
Idle w/ Prevention	74	$147.22	$331.75	$24.54	$55.29
No Idle	53	$104.27	$234.96	$17.38	$39.16
No Idle w/ Prevention	53	$104.27	$234.96	$17.38	$39.16
Crosslinked Gel	**Total Time running (min)**	**Total Emissions Cost Minimum**	**Total Emissions Cost Max**	**Pump Unit Cost Minimum**	**Pump Unit Cost Max**
Idle	193	$1,673.01	$3,770.02	$72.74	$163.91
Idle w/ Prevention	189	$1,640.89	$3,697.65	$71.34	$160.77
No Idle	169	$1,466.25	$3,304.09	$63.75	$143.66
No Idle w/ Prevention	169	$1,466.25	$3,304.09	$63.75	$143.66

Examining emissions, it is also unsurprising that linear gel with the fewest pump requirements performs the best in an emissions comparison amongst the three fluid types. Additionally, the scenario where pumps are not kept idling is the best scenario across all fluid types. Emissions are slightly higher amongst the pumps idling with preventative maintenance versus those idling without preventative maintenance because of the greater NPT associated with the later scenario. Linear gel with non-idling engines in a preventative or non-preventative maintenance scenario produces the best result for emissions. In the tested scenarios, we placed 100% load on each pump, as it would yield the best cost values. The purpose of the scenario is to provide a best efficiency case so that we could ultimately find the best optimized case. The cost and emission data used for our pump is listed previously in this document.

Having considered all 3 fluid choices, the pump performance factors, and our geology, linear gel without idling and a non-preventative maintenance produces a balanced option for lessening both NPT and emissions. This is also true for all the fluid cases.

5. FUTURE OF FRACTURING OPERATIONS

The above study shows that the main reason of high emissions is linked to the fact that diesel engines used as main driver for the frac pumps need to stay idle (emission intense) or to be used at less than 90% load.

One alternative to this is the newly Electric Frac Units that are currently available on the market. The main characteristic of these new units consists of the replacement of the diesel engine with a highly controllable electric motor which will drive the pump. Using electric motors to power the pumps allows the unit to use electricity from at least two different sources: from the grid (when available) or from a more efficient high-power generator (which is very common).

This trend has a spectacular evolution according to Matt Johnson, the president and chief executive of Primary Vision: “It’s amazing that [e-fleets] accounted for roughly 3% of the market about 2 months ago and now they’re potentially about 30%”.

According to Jacobs (2020), in May 2020 “Three companies own this entire space which has been driven by the shale sector’s growing concerns over noise levels, fuel costs, and carbon footprints. Evolution Well Services and US Well Services, both based in the Houston area, each are estimated to be operating six electric pumping spreads. Midland-based ProPetro operates the remaining three e-fleets.”

NOV as hardware manufacturer introduces the NOV Ideal eFrac Fleet which is using an electric generator powered by a turbine with a 13.8KV power. The concept is capable to reduce up to 89% fuel costs, 40% in total cost of ownership and 42% in over-the-road traffic. (NOV.com)

A recent post on their website, Halliburton has announced their first eFrac fleet that is using the power grid electricity (Halliburton.com). A grid powered Frac fleet could be in the advantage of the geothermal resource development in the cities or nearby.

With more geothermal developments and in particularly with the emission reduction becoming the priority of the years to come, Electric Frac Fleets will become the main component of geothermal development. Currently multifuel field generators exists on the market which also may allow a better emission management through better fuel selection.

In the near future a combination of the two techniques (full electric using the power grid and full electric using the onsite generator) may also be possible, in which the power generator will be connected to the grid, allowing the system to pump the excess electricity in the grid (during pump idle processes). Such experiments have been reported for modern drilling rigs.

6. CONCLUSIONS

Well stimulation design is a necessary element in the development of a profitable well (geothermal or not). This design process requires many areas of optimization in completion technologies.

This paper point to designing a fracture stimulation plan with focus on the optimization of frac pump in order to identify the effect of the frac job on emissions and NPT.

Our results evidence that the most balanced choice for both optimizing NPT and emissions is the created linear gel design using a non-preventative maintenance plan and non-idling pumps. This implies that frac fluid selection plays a major role in emission optimization of a frac job.

This plan will yield an average NPT of 13 minutes per stage and have minimum and maximum emissions cost per stage of $104 and $204, respectively.

In a broader sense, if a different fluid type is desired, the case of non-preventative maintenance and non-idling engines is the most balanced case for optimizing both NPT and emissions for all fluids.

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