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Comparing the Productivity and Lithium Concentration of Geothermal and Oilfield Brine Projects in the US and Europe

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ABSTRACT

Lithium concentrate (LC) is crucial for energy transition, particularly the Electric Vehicles battery industry. Currently, sourcing LC from hard rock mines has a high carbon footprint. After mining the lithium-bearing rocks, they require roasting with fossil fuels and dissolution with substantial amounts of acid to produce LC. Direct Lithium Extraction (DLE) from brines has the potential to be more cost-effective and environmentally friendly. DLE can selectively extract lithium (Li) from brines with an efficiency of 90%, surpassing the evaporation methods used in conventional projects. The current minimum grade for commercial DLE projects is 100 ppm while 150-400 ppm has been reported in various brine resources globally, including geothermal and oil field resources.

In this presentation, we compare geothermal and oilfield Li brine projects in diverse geological settings in the US and Europe. Geothermal brines exhibit higher temperatures and are saturated with silica, necessitating its removal from the brine using clarifiers. While this challenge is not novel to the geothermal industry, it demands meticulous engineering and adds additional operating and capital costs. The energy contained within geothermal brines can also be utilized directly to provide heating or converted into electricity to generate additional revenue and mitigate the carbon footprint of the Li brine project. Well productivity is the most critical and most sensitive subsurface uncertainty for Li brine projects. Comparing projects can be done based on reservoir permeability-thickness (kh). Individual wells can be characterized by their Productivity Index (PI), which is directly proportional to kh.

Our analysis reveals that the Li grade has a relatively smaller impact on the viability of a project compared to well PI. We demonstrate this through wellbore modeling, which shows that the well productivity for pumped wells targeting comparatively low permeability formations associated with oilfield brines in the USA is typically limited to approximately 400 GPM (90 m^3/h) when using Electrical Submersible Pumps (ESP) set at a depth of around 5,000 feet (1,500 m). Similarly, moderate temperature fractured geothermal reservoirs in Europe also require pumped wells, but they achieve productivity flowrates of 250 m^3/h when using Line Shaft Pumps (LSP) or ESPs set at depths of 3,300 feet (1,000 m). On the other hand, some of the most productive high temperature geothermal reservoirs in the USA can produce over 450 m^3/h from self-lifting wells. Considering the increasing complexity and costs associated with wells targeting each studied reservoir, it becomes challenging to compare the cost of producing a ton of Li from each project. In this

presentation, we propose a method to compare three Li brine projects from a subsurface perspective, utilizing wellbore modeling and due diligence work conducted by the authors.

1. Basis of Comparison

Selected basins with brines exhibiting high concentration of lithium are compared on the basis of potential lithium production per well; lithium brine projects analyzed include:

A. Pumped wells targeting the Smackover oilfield brines in Arkansas
    - Representative project is the Standard Lithium South West Arkansas and the Lanxess South project in Union County, Arkansas.
    - The Lanxess South project is documented in a Definitive Feasibility Study by Brush et al. (2023).

B. Pumped wells targeting the medium-temperature geothermal brines of the Upper Rhine Graben in France and Germany
    - Representative projects are the Lionheart and Taro project from Vulcan Energy in German.
    - These projects are documented in a Definitive Feasibility Study by Wedin et al. (2023).

C. Self-lifting high temperature geothermal brines in the Salton Sea in California.
    - A representative project is the Hell's Kitchen project from Controlled Thermal Resources in the Salton Sea.
    - Lithium projects in the Salton Sea are described in a project report prepared by Lawrence Berkeley National Laboratory (2023).

In undertaking due diligence for these and other brine projects, we have found that the initial well productivity is the single most important uncertainty / sensitivity for a lithium brine project.

The potential lithium production per well for each of the analysed projects is estimated using the following steps for each of the three selected projects, with a focus on the Smackover:

1. When the well productivity is not already known from well testing, representative or average permeability-thickness (kh) is estimated for the target reservoirs.
2. Well productivity is primarily related to kh by the fluid flow (diffusivity) equation, although viscosity and fluid density are also factors. A simplified relationship is used to derive the Productivity Index (PI) from kh for a given viscosity and fluid density.
3. A representative production rate is estimated by wellbore modelling for a candidate well design, for a pumped well or a self-lifting well, depending on the selected reservoir.
4. The total production rates are multiplied by the estimated average Li concentrations to generate estimates of Li production (in tonnes per annum of lithium metal).

Other characteristics of the three selected projects are discussed qualitatively based on the author's experience with due diligence of lithium brine projects (including CAPEX, OPEX, impurities, lithium dilution rates, etc.).

2. Wellbore modelling – application to the Smackover

2.1 Type wells

For each project, a 'type well' was defined to be used in the wellbore modelling. Figure 1 shows the type well used for the representative Smackover project analyzed in this paper. The Volsung software package is used to carry out the wellbore modelling (Franz et al., 2019).

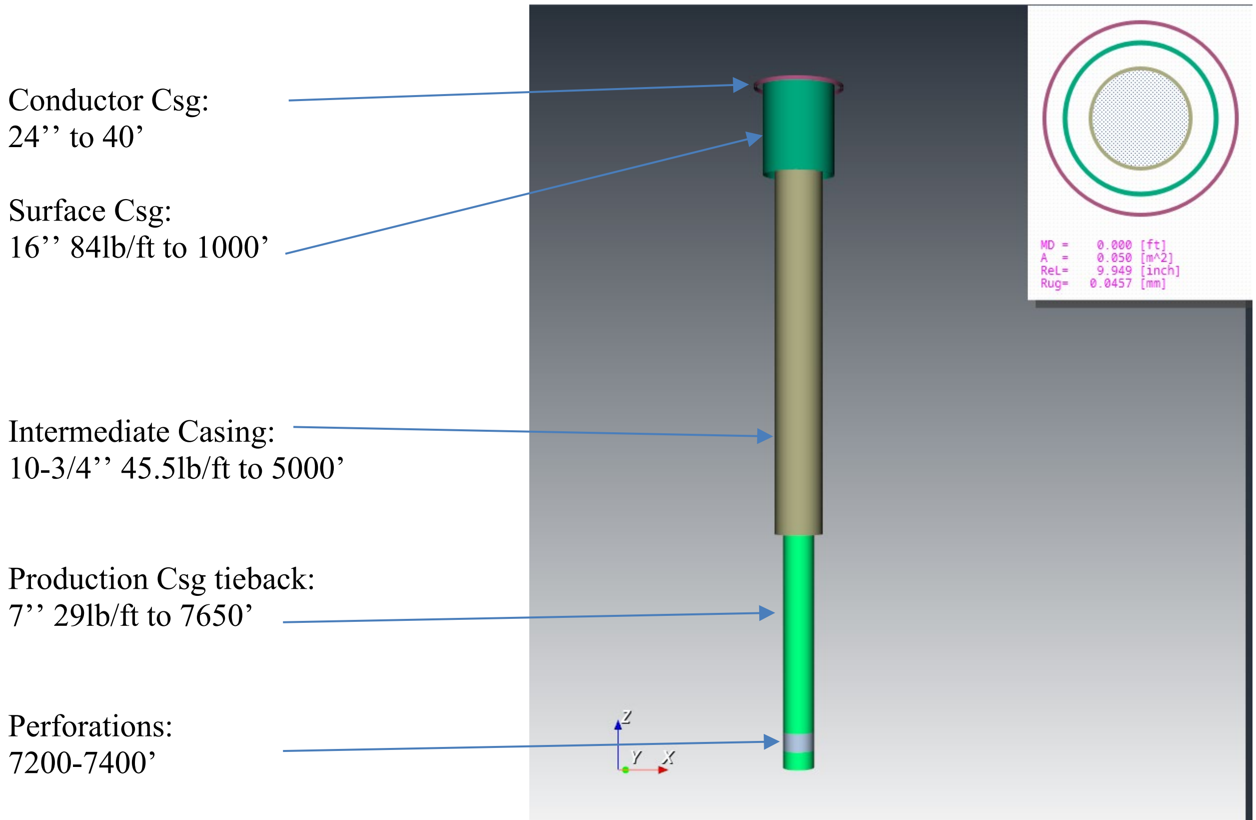

Figure 1: Smackover type well after Brush et al. (2023)

2.2 Fluid Properties

Fluid properties, namely viscosity and density, vary with pressure, temperature and the salt mass fraction. For this paper we use a water plus sodium chloride equation of state in Volsung based on the Battistelli et al. (1997) and Battistelli (2012) publications.

- Reservoir pressure is estimated using the fluid density gradient in the Smackover reported by Bruce et al. (1944) prior to substantial petroleum extraction. This leads to a static reservoir pressure of 3,690 psi at 7,400 ft.
- Reservoir temperature is estimated using a surface temperature of 17ºC from Roy et al. (1980) and an average geothermal gradient of 32 ºC/km for South West Arkansas from Nondorf (2023). This leads to a static reservoir temperature of 89 ºC at 7,400 ft.
- Salinity is reported to be 230,000 mg/L with fluid of 1.2 Specific Gravity (SG) (at lab temperature and pressure) or 26% NaCl (XNaCL = 0.26).

The resulting thermodynamic conditions at reservoir level are calculated below:

- **Fluid Density** = 1,172 kg/m^3 (SG is slightly lower than 1.2 at reservoir level because of the elevated temperature)
- **Fluid Viscosity** = 0.69 cP (the high salinity increases the viscosity of the fluid despite the elevated temperature)

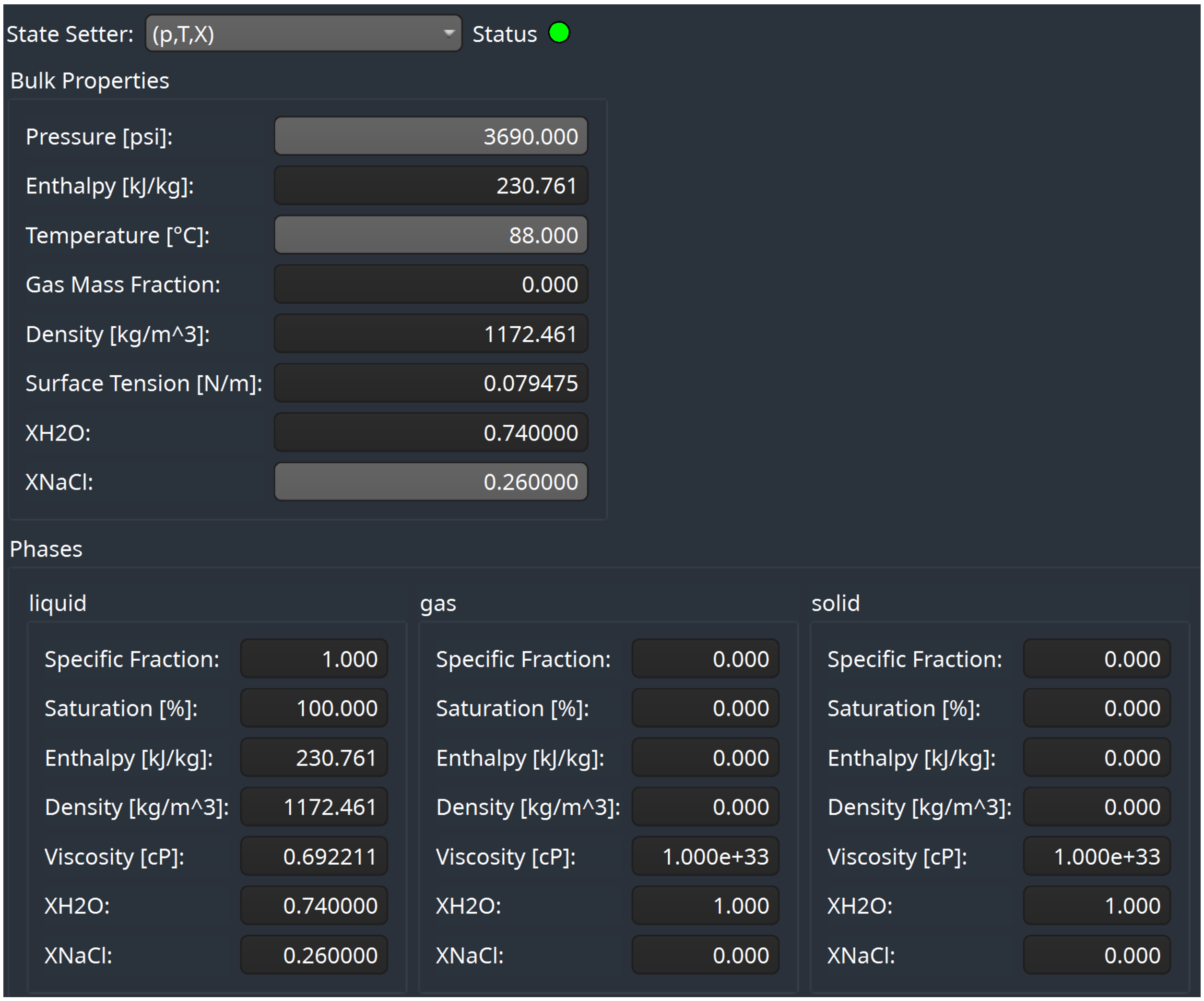

Figure 2: Modelled thermodynamic conditions in Smackover type well at 7,400 ft (static conditions)

2.3 Reservoir properties

The Smackover Oil Field was discovered in 1922. Dyman et al (2006) used nearly 7,000 wells drilled in the subsequent oil rush to produce the map of areal extent based on well formation tops (Figure 3). The high lithium concentration appears to be collocated with the presence of the sour gas belt in Arkansas where several explorers have secured exploration leases (Standard Lithium, Exxon, etc.).

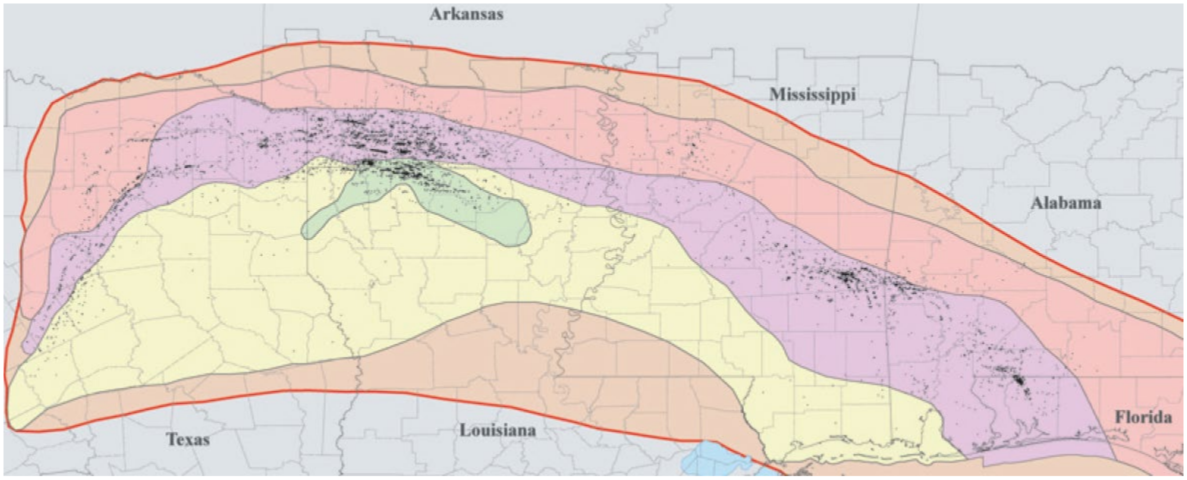

Figure 3: Map of areal extent of the Smackover Basin based on well formation tops (Dyman et al., 2006).

Montague 1 (Figure 4) is used to describe the characteristics of a typical productive Smackover well. Net reservoir pay is defined by zones of porosity greater than 6%, though most of the permeability occurs in zones with a porosity >12-15%. Much of the net pay is concentrated in the upper 200 ft of the Upper Smackover. Permeability-thickness is estimated at 5,000 md.ft or about 1,525 md.m (i.e., an average of 50 md over 100 ft).

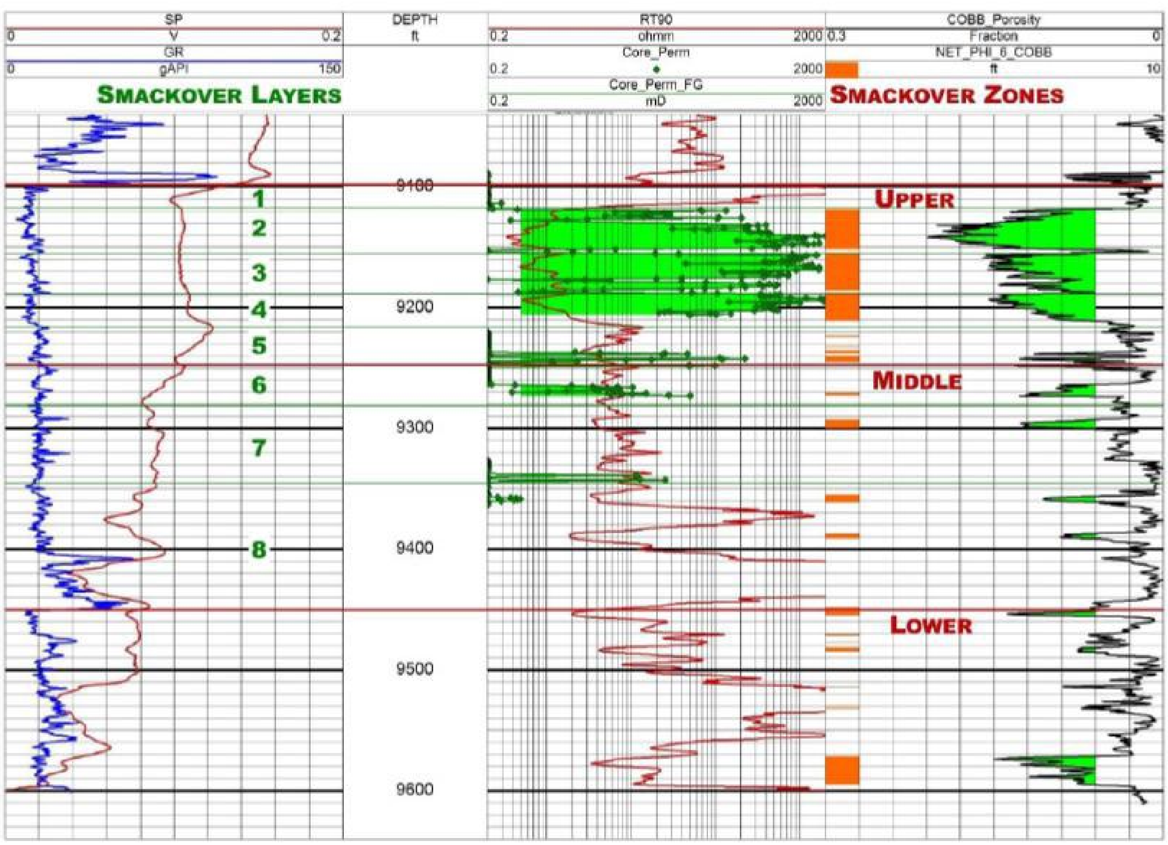

Figure 4: Montague 1 type well. Note that the Smackover reservoir is deeper in this well than in the type well presented in Figure 1; reservoir characteristics, however, are similar.

2.5 Well productivity

Well productivity is derived from the famous Dupuit-Thiem (1906) equation valid for radial, infinite -acting conditions which can be expressed to incorporate the skin effect via the concept of an effective radius:

$$p_w = p_r - q \cdot \frac{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)}{2 \cdot \pi \cdot \mathrm{kh}} \tag{1}$$

$$p_r - p_w = dp = q \cdot \frac{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)}{2 \cdot \pi \cdot \mathrm{kh}} \tag{2}$$

$$r_{w*} = r_w \cdot e^{-S} \tag{3}$$

where p_w is the wellbore pressure, p_r is the reservoir pressure at a distance r from the well (also referred as radius of influence if the pressure is not impacted by pumping from the well beyond that radius), q is the flowrate, μ is the fluid viscosity, r_{w*} is the effective wellbore radius, kh is the permeability thickness, dp is the pressure drawdown and S is the skin factor (S = +0 in the absence of stimulation and/or permeability impairment from residual drilling fluids).

The volumetric PI in SI units can be derived by substituting PI for q/dp :

$$PI_{vol} = \frac{q}{dP} = \frac{2 \cdot \pi \cdot \mathrm{kh}}{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)} \tag{4}$$

Using units of darcy.m for the permeability thickness and cP for the viscosity, the PI (m^3/bar) can be calculated using:

$$PI_{\left(\frac{m^3}{h}/bar\right)} = 2 \cdot \pi \cdot 9.869233 \cdot 10^{-13} \cdot 1000 \cdot 10^5 \cdot 3600 \frac{kh}{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)} = 2.2324 \cdot \frac{kh}{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)} \tag{5}$$

In oilfield units of GPM/psi, the equation can be further simplified to:

$$PI_{(GPM/psi)} = 2.2324 \cdot \frac{264.127}{60} / 14.5038 \cdot \frac{kh}{\mu \cdot \ln\left(\frac{r_0}{r_{w*}}\right)} = 0.6776 \cdot \frac{kh}{\mu \cdot \ln\left(\frac{r}{r_{w*}}\right)} \tag{6}$$

Approximation of the PI is not every sensitive to the value of r since it is logarithmic. To highlight this and select an appropriate value for r, we refer to the concept of pressure disturbance, which can be derived from diffusivity equation:

$$r_{time=t} = \sqrt{\frac{4kt}{\phi \mu c_t}} \tag{7}$$

Using units of darcy for the permeability, psi^{-1} for the compressibility, cP for the viscosity, days for the time, and feet for the radius, this can be simplified to:

$$r_{time=t} = \sqrt{\frac{4kt \cdot 3600 \cdot 24 \cdot 9.869233 \cdot 10^{-13}}{\phi \mu c_t / 6894.76/1000}} = 5.031 \sqrt{\frac{kt}{\phi \mu c_t}} \tag{8}$$

where t is the time, ϕ is the porosity and c_t is the total compressibility. Porosity and total compressibility are typically correlated (compressibility is higher for low porosity values).

Values of r are calculated for typical low, mid, high values of the permeability, porosity and total compressibility in the table below at a time of 1 day for a wellbore diameter of 9.5 inch.

The logarithm ratio is also calculated below (in brackets) to illustrate the low sensitivity of the logarithm ratio to the values of permeability, porosity and total compressibility (e.g., $\ln\left(\frac{r}{r_{w*}}\right) = 8.7$ +/- 7%). Results are shown in Table 1.

Table 1: Radius of influence and logarithm ratio of radius of influence to well radius for a range of typical permeability and porosity/compressibility values

r In brackets $\ln\left(\frac{r}{r_{w*}}\right)$	k = 0.05 D	k = 0.10 D	k = 1.00 D
c_t=10.10^{-6} psi^{-1} ϕ=5%	1915 ft (8.5)	2709 ft (8.8)	4691ft (9.4)
c_t=5.10^{-6} psi^{-1} ϕ=15%	1564 ft (8.3)	2212 ft (8.6)	3831 ft (9.2)
c_t=3.10^{-6} psi^{-1} ϕ=30%	1428 ft (8.2)	2019 ft (9.5)	3497 ft (9.2)

Considering this, the PI can be further simplified to

$$\Gamma \cdot PI_{(GPM/psi)} = \frac{kh}{\mu} \tag{9}$$

where Γ is a factor related to the radius of influence, with calculated values in the table below to highlight the low sensitivity of the PI to the radius of influence. Results are shown in Table 2.

Table 2: Ratio between permeability thickness divided by viscosity and Productivity index when expressed in oil and gas units

Γ	k = 0.05 D	k = 0.10 D	k = 0.30 D
c_t=10.10^{-6} psi^{-1} ϕ=5%	13	13	14
c_t=5.10^{-6} psi^{-1} ϕ=15%	12	13	14
c_t=3.10^{-6} psi^{-1} ϕ=30%	12	13	13

For the comparatively lower permeability of the Smackover formation, the relationship simplifies to the same as the relationship proposed by Elliot Yearsley (2019) :

$$12 \cdot PI_{(GPM/psi)} \approx \frac{kh}{\mu} \tag{10}$$

For higher permeabilities, like those of geothermal reservoirs in the Salton Sea, the relationship becomes:

$$14 \cdot PI_{(GPM/psi)} \approx \frac{kh}{\mu} \tag{11}$$

Given the permeability thickness and viscosity values shown above, the resulting PI for the Lanxess South example is ≈ 0.18 GPM/psi or ≈ 0.60 m^3/h/bar. Given the density of the fluid is 1,172 kg/m^3, the mass rate PI is ≈ 0.70 tph/bar.

2.4 Electrical Submersible Pump

In the case of pumped wells, the pump rate is constrained by the pump power and pressure drawdown with limits set based on the type well above. For this paper, the pump curve of a M675C ESP from REDA Schlumberger is used (Figure 5) as a guide recognizing, that there are other pump models that may be more adequate in practice.

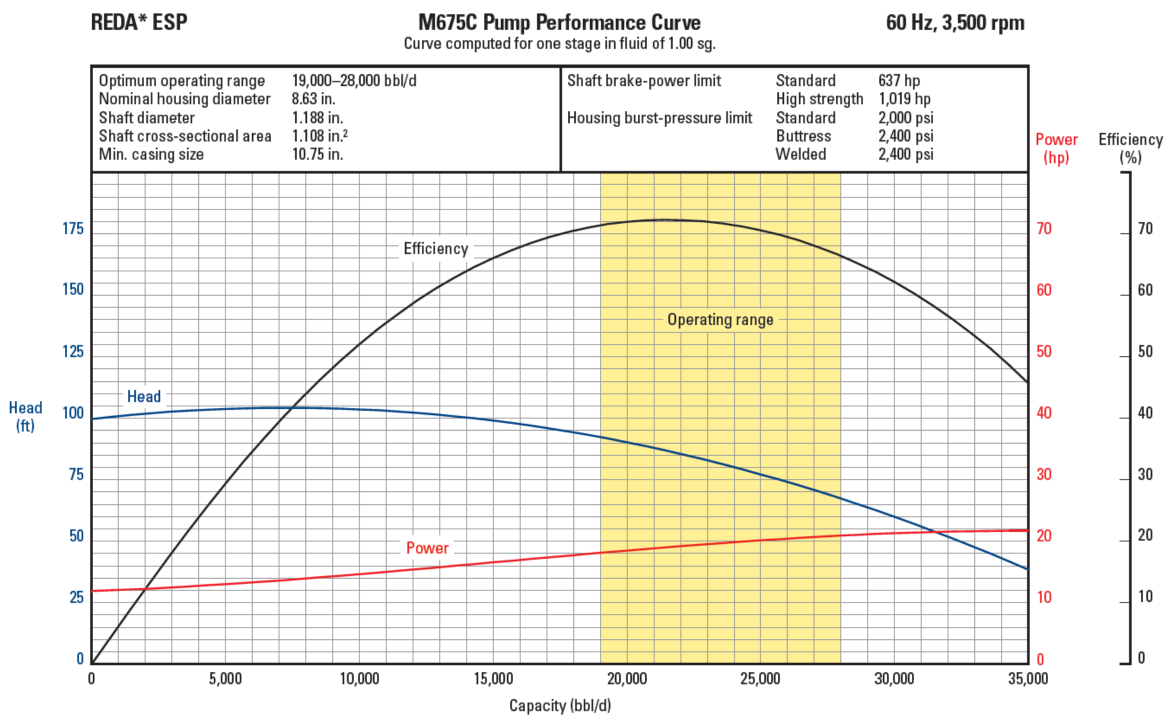

Figure 5: Pump curve for one stage (provided by Schlumberger for fluid of 1.0 SG – relevant corrections are applied during wellbore modelling).

2.5 Wellbore modelling Results

The Volsung wellbore model is run to generate a deliverability curve with the selected pump (55 stages) at a constant 3500 rpm within the operating range of the pump (19,000 – 28,000 bbl/d or about 345-405 GPM with 1.0 SG or about 78-92 tph).

Results shown in Figure 6 suggest 85 tph is achievable with a surface wellhead pressure greater than 100 psi, which is sufficient for downstream processes noting a booster pump may be required in some case where the brine needs to be transported some distance away from the well pad to a central facility for processing. This is the same order of magnitude of mass rate reported in the Definitive Feasibility Study by Brush et al. (2023) for the Standard Lithium Lanxess South project.

At that setpoint the power approaches the shaft-brake power limit for a high strength pump (1,019 hp limit), so 85 tph would be a maximum capacity for the selected pump model.

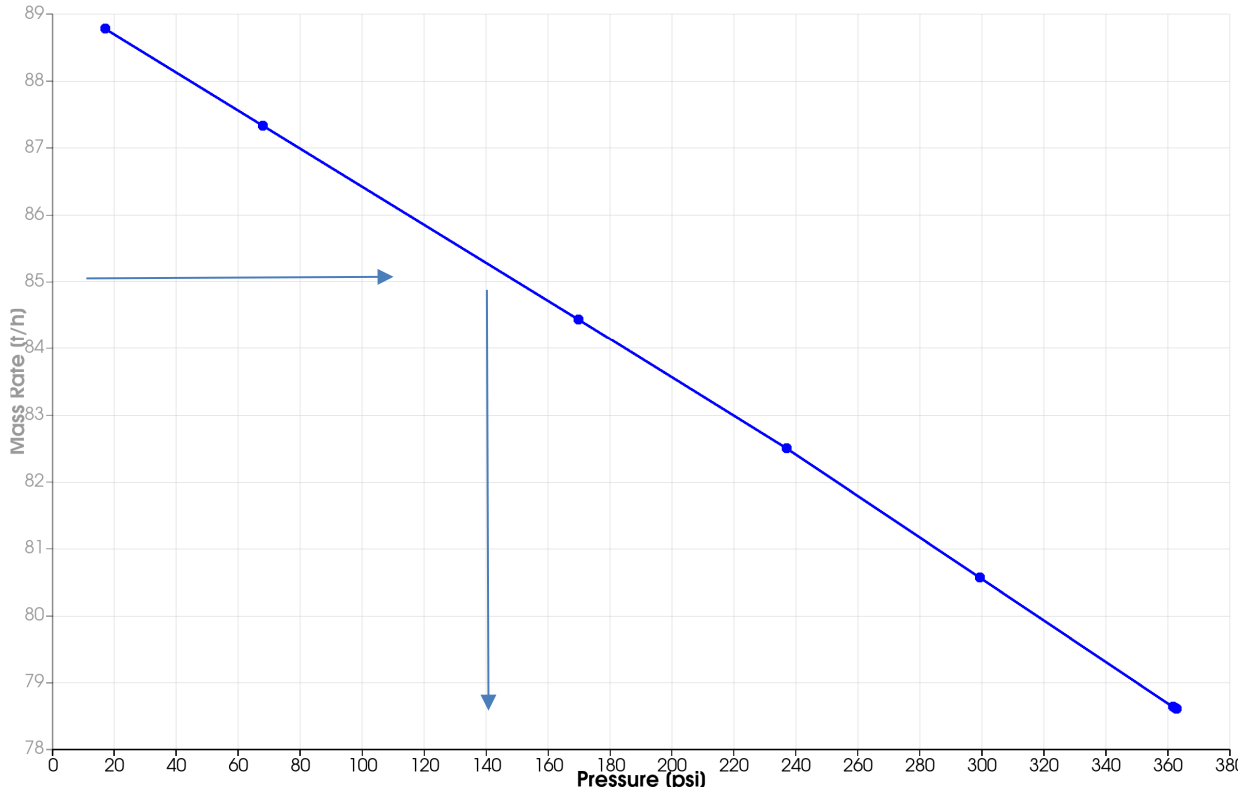

Figure 6: Wellbore modelling results with selected submersible pump at 3500 rpm.

While other ESP models with higher lift head capacity exist, it should be noted that pumped wells are typically designed to allow for some reservoir pressure decline both from a dynamic head to prevent cavitation of the pump (Figure 7) and from a lift head capacity point of view (Figure 8).

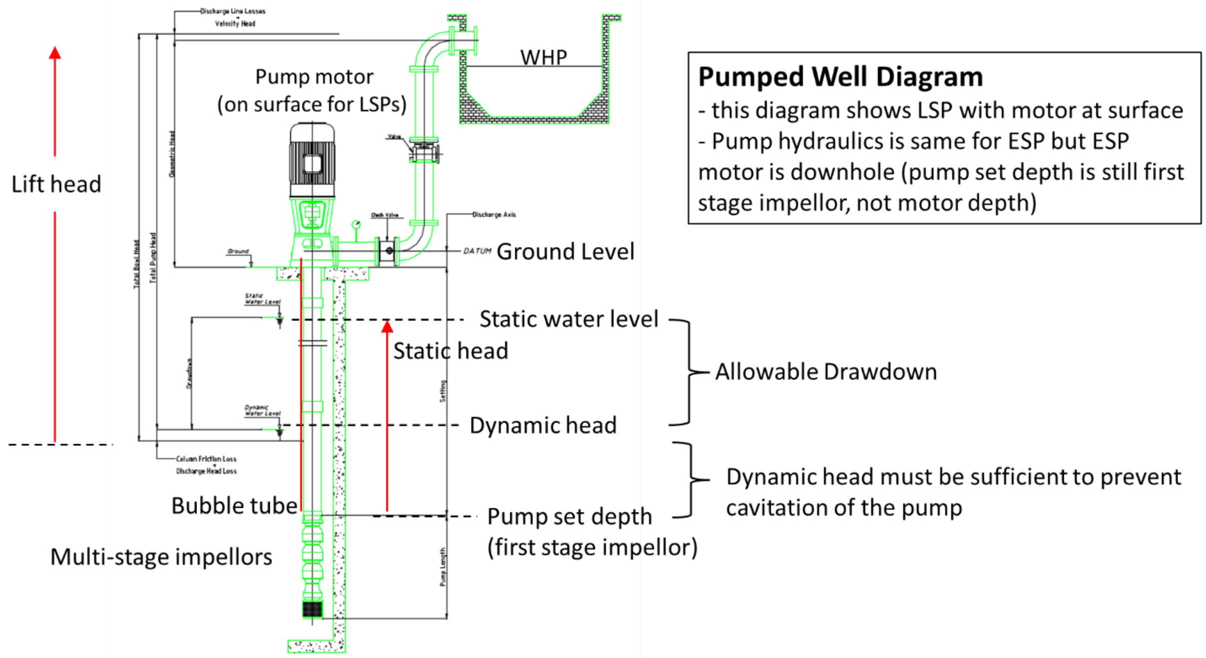

Figure 7: Pumped Well Diagram

For the scenario modelled above, any substantial reservoir pressure decline would result in a drop of mass rate if the wellhead pressure must be maintained above 100 psi due to insufficient lift head spare capacity.

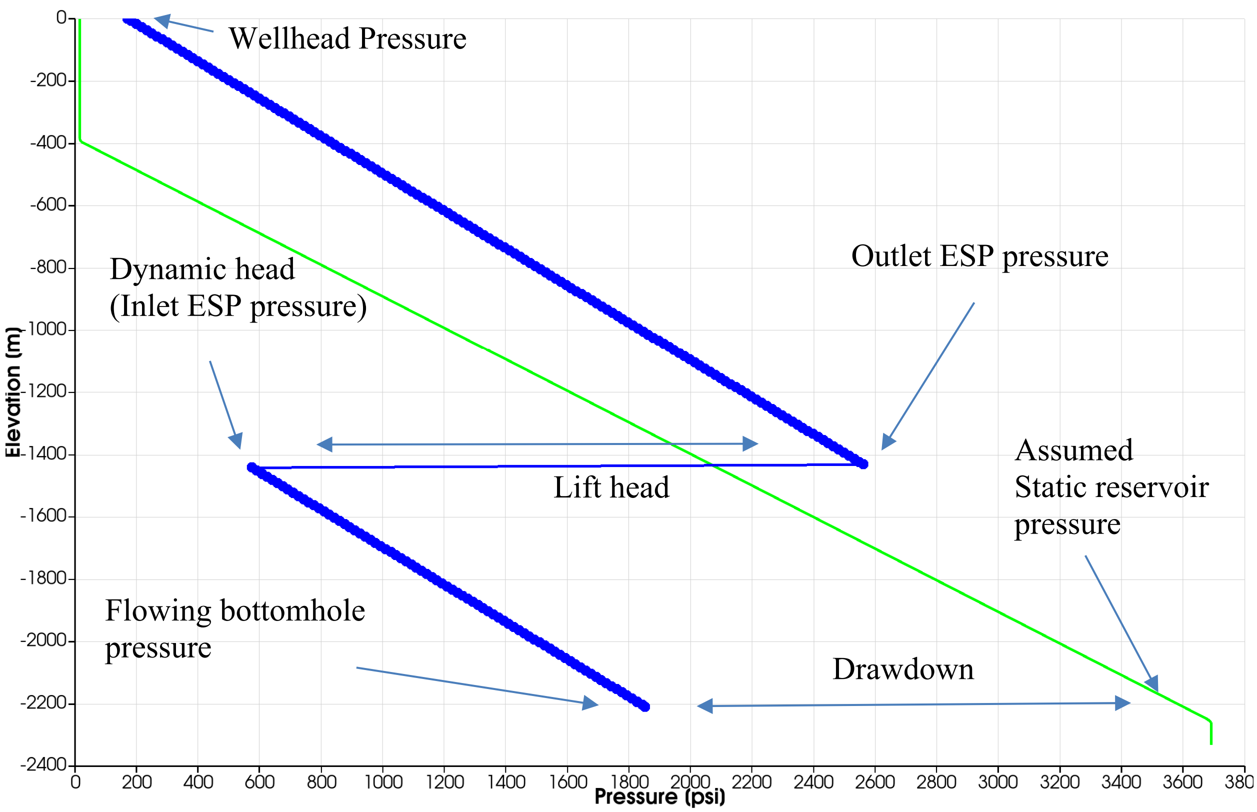

Figure 8: Wellbore modelling results at 85 tph showing wellbore and pump column pressure vs elevation.

Figure 8 shows the profile plot of the pressure from the wellhead down to the perforated interval at 7,200 to 7,400 ft. The ESP inlet pressure is much greater than 100 psi, suggesting that a more powerful ESP could be used to maintain the 85 tph mass rate should reservoir pressure decline (e.g., dynamic head is sufficient to prevent the pump from running dry) and/or produce up to 100 tph in the absence of reservoir pressure decline (subject to sufficient left head).

2.6 Lithium Concentration

Lithium concentrations of 201-227 mg/L are reported in the Definitive Feasibility Study by Brush et al. (2023) for the Standard Lithium Lanxess South project. In the Standard Lithium South West project, the reported concentrations are up to 437 mg/L.

The lithium elemental production, in tpa Li, is calculated using the formula below:

$$tpa\ Li = q \cdot [Li] \cdot \frac{1000}{\rho} \cdot 24 \cdot \frac{365}{10^9} \qquad (22)$$

where $[Li]$ is the lithium concentration values in mg/L and ρ is the density of the brine in kg/m^3. Thus, the resulting lithium production from a single well range from ≈125 to 319 tpa Li.

3. Comparison with selected geothermal brines projects

The results from the assessment of a Smackover type well are compared to geothermal brine projects in the Table 3 below (SG is provided at the produced fluid temperature).

Table 3: Comparison of selected brine projects based on wellbore modelling of "type wells"

Project	Type	PI tph/bar	Massrate tph	SG** -	[Li] mg/L	Li production tpa	Pump
A – Smackover	Vertical 7,400 ft MD	0.7*	85-100*	1.2	201-437	125-319[1]	About 1,000 hp ESP
B – Rhine Graben	Directional 11,500 ft MD	3	234-252	1.0	180	369-397[2]	
C – Salton Sea	Vertical 8,000 to 12,000 ft MD	50	500-900	1.2	141-287	515-1885[3]	Self-lifting

*: 85 tph is possible with the selected ESP while a mass rate of 100 tph is theoretically achievable with an ESP with a higher lift head capacity. Furthermore, higher mass rate may be achieved from deviated wells with multilateral completions (skin < 0) and/or wells exhibiting a higher permeability thickness.

[1]: No dilution occurs according to the reservoir modelling presented in Brush et al. (2023). However, it assumes injection occurs at a deeper level within the Smackover. If that cannot be done because of the lack of permeability in the Middle and Lower Smackover and injection needs to occur in the Upper Smackover instead, it is likely that dilution rates would apply.

[2]: 1.2-3.2% lithium dilution per year (Weddin et al., 2023).. Consequently, in the absence of make-up wells, the Li production would decline after breakthrough of the injected water.

[3] : Modelling from O'Sullivan et al. (2024) suggests dilution rates that would apply to production from the Salton Sea geothermal field would be in the same ball park as those presented in Weddin et al. (2023) and possibly closer to the upper end of the range depending on the chosen reinjection strategy based on the modelled decline of lithium production flow from about 3 tph to 1.0-1.6 tph after 19 years of production.

This comparison highlights the importance of well productivity for lithium projects and shows geothermal reservoirs have higher flowrates than oil and gas reservoirs such as the Smackover. Other criteria the authors have considered when undertaking due diligence of lithium brine projects include:

- Success rate given geology and reservoir characteristics
- Complexity and cost of the wells (e.g., simple vertical wells in the Smackover, complex J-wells in the Rhine Graben and high temperature wells requiring corrosion-resistant alloy (CRA) liners in the Salton Sea)
- Revenue generated from geothermal heat and electricity generation
- Additional surface infrastructure costs for geothermal brines (inclusive of silica clarifiers)
- Presence of impurities in the brine (Si, Mn, Zn, Ca, Mg, B) that can affect the efficiency of the DLE process
- DLE recovery rate that can be achieved with the produced brine
- Specific brine handling costs (sour gas in the Smackover)
- Typical land access and regulatory aspects
- Pumping and injection costs and associated operating costs
- Lithium dilution in % per year depending on selected reservoir injection strategy

Discussing these other factors and their impact on project feasibility in detail is beyond the scope of this paper but we generally find that the large difference in the calculated production rates will generally make productive geothermal reservoirs more attractive for lithium production.

4. Conclusion

Results presented here are indicative. They are intended to compare lithium flow rates based on average or representative permeability and Li concentration.

Key conclusions are highlighted below

- Except for the Salton Sea (Lawrence Berkeley National Laboratory [2023]), no actual lithium production rate data are available in the public domain.
- Geothermal reservoirs typically have higher flow rates than oil and gas reservoirs.
- To date, the high lithium concentrations identified in petroleum basins occur in the brine in the water leg or downdip from oil reservoirs, and will require pump-assisted production from dedicated wells completed for lithium production as demonstrated by wellbore modelling for the Smackover (in some cases, existing wells may be able to be repurposed as is proposed with Standard Lanxess project).
- Maximum pump rates have been estimated based on the Productivity Index, which is proportional to the average permeability-thickness of the reservoir.
- The Salton Sea has the highest potential lithium production rate, followed by the Rhine Graben and then the Smackover. The Smackover wells, however, are less expensive to drill, making it an attractive area of interest after the Salton Sea in the USA.
- In general, while geothermal reservoirs may be more complex and expensive to drill compared to shallower oil and gas reservoirs, the large difference in the calculated production rates will generally make them more attractive for lithium production.

Acknowledgement

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