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Pressure-Temperature-Spinner and Geophysical Logs, Injection Tests, Laboratory Testing of Core and Cuttings, and their Application to Stimulation Planning for the Ormat Wells of Opportunity Project

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ABSTRACT

The goal of this ongoing Department of Energy (DOE)-funded Ormat-GeothermEx Wells of Opportunity Project is to use stimulation techniques, guided by geomechanical modeling and analytical methods, to sequentially stimulate two existing wells with long open-hole sections at two operating fields in Nevada. These stimulations have the potential generation impact of up to several MWs at the Don A. Campbell (DAC) and Jersey Valley (JV) operating geothermal power plants. The subject wells for stimulation are DAC idle well 68-1RD and JV injection well 14-34.

This paper describes various tests and data collection activities (and their results) conducted to understand and characterize the readiness of each well and wellsite for stimulation. For both wells, pressure-temperature-spinner (PTS) logs, geophysical logs and injection test data have been collected following extensive reviews of existing well and geothermal resource information. Additionally, laboratory testing has been performed on existing samples of representative core and cuttings to characterize the petrology and mineralogy of the formations of interest for stimulation of both wells. Herein we describe the usefulness of the data collected during BP1 activities for stimulation planning, and how they are used to inform the preparation of static geomechanical models and stimulation effectiveness models for the DAC and JV well sites, and for stimulation planning in general for geothermal wells with low productivity elsewhere.

Keywords: Geophysical logging, pressure temperature spinner, data collection, enhanced geothermal systems, stimulation planning, Nevada

1. INTRODUCTION

The aim of the Wells of Opportunity Project is to sequentially stimulate two existing wells with long open-hole sections in operating fields in Nevada. Both these wells have potential generation impact of up to several MWs at each facility. Figures 1 and 2 respectively illustrate the subject wells in the project locations in Nevada. The details of these wells are summarized as follows:

- Don A. Campbell (DAC) Project, Idle Well 68-1RD (Figure 1): The 28-MWe DAC project (in Mineral County) has been operating since 2013. The target EGS well was initially used for injection, but was shut in soon thereafter because of injection breakthrough. The well was then re-drilled into a deeper section of volcanic rock and encountered an attractive temperature (280°F) but with low permeability. The intention is to stimulate well 68-1RD (current injectivity is 3.5 gpm/psi as determined during injection testing in 2025) and use it for production.

- Jersey Valley (JV) Project, Injection Well 14-34 (Figure 2): The 8-MWe JV project (in Pershing County) has operated since 2010 with two active production wells and four active injection wells. While the production wells have moderate to high permeability, injection must be placed in low permeability zones to achieve adequate heat sweep. Injection well 14-34 (~260-275°F) is the poorest performer, with an injectivity of 2.2 gpm/psi as determined during injection testing in 2025. The objective is to connect the well to the range-front fault system to maximize heat sweep in a reservoir with temperatures greater than 300°F, to reduce injection pressures (and the associated parasitic pumping power requirement) and increase power output capacity (the project is injection-limited at present).

The duration of this project has been scheduled for approximately three years (as first described in Hackett *et al.* (2025)). The first phase of this project, Budget Period 1 (BP1), was recently completed in December 2025. This phase was critical for data collection activities, stimulation planning and costing, and logistical coordination. Tables 1 and 2 describe the timeline of key data collection activities during BP1. As a result of the iterative nature of stimulation planning to include new data being collected, wellbore readiness and logistical coordination tasks required timeline modification. Key related activities have defined the project's critical path: geophysical log data collection, geomechanical and stimulation effectiveness modeling, and iterative stimulation planning and costing. Table 1 and 2 illustrate a timeline of the critical activities that were undertaken in BP1 for both wells.

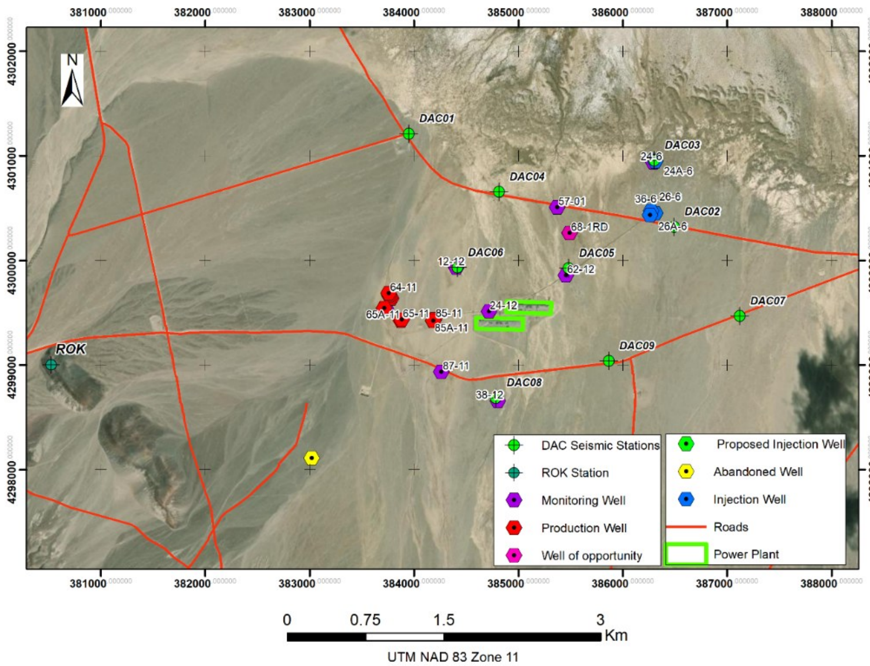


Figure 1: Aerial map of Don A. Campbell (DAC) field, including injection and production wells, subject well for stimulation (68-1RD), and current seismic monitoring stations

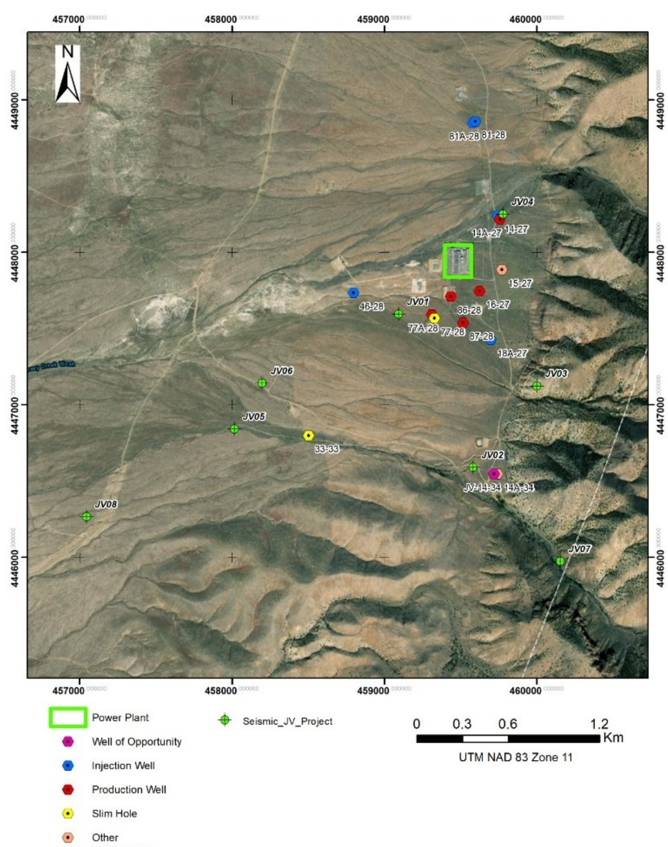


Figure 2: Aerial map of Jersey Valley (JV) field, including injection and production wells, subject well for stimulation (14-34), and current seismic monitoring stations

Table 1: Timeline of key data collection events at DAC 68-1RD

March to October 2025	Laboratory tests of well cuttings and core samples (some tests in progress)
June 2025	Static PTS log collection
June 2025	Injection testing
June 2025	Acquisition of geophysical logs
Aug 2025	Stimulation plan design review
Oct 2025	Completion of 1-D Mechanical Earth Model (MEM)
Nov 2025	Design the preliminary acid spearhead treatment
Ongoing	Stimulation effectiveness modeling

Table 2: Timeline of key data collection events at JV 14-34

March 2025	Laboratory tests of well cuttings
Aug 2025	Static PTS log collection
Aug 2025	Long-term injection testing
Aug 2025	Stimulation plan design review
Oct 2025	Acquisition of geophysical logs
Nov 2025	Design the preliminary acid spearhead treatment
Dec 2025	Completion of 1-D Mechanical Earth Model
Ongoing	Stimulation effectiveness modeling

2. BUDGET PERIOD 1 (BP1) RESULTS

BP1 activities for the WOO project have focused on evaluating the technical characteristics and readiness of the wells for stimulation using historical and newly acquired data (*e.g.,* well logs, well test data, geochemical data, analytical models, and geomechanical models). This section presents the results and interpretation of newly acquired data in the past 1.5 years for wells DAC 68-1RD and JV 14-34.

2.1 Injection Tests

Injection tests were conducted for the DAC and JV wells as part of the data collection efforts during BP1.

The DAC well was tested previously in 2019 and re-tested in Q2 2025. Both tests of the DAC well included pressure fall-off monitoring, and yielded similar injectivity indexes (approximately 3 gpm/psia in 2019 and 3.5 gpm/psia in Q2 2025). Because the goal of stimulating the DAC well is to use it as a production well, an in-house pumped wellbore model (Sanyal *et al*., 2007) was used to estimate the DAC well's productivity prior to the planned stimulation. This analysis provided an estimate of the DAC well's current productivity: 0.6 MW-net / 1.1 MW-gross, which represents a baseline for comparison to the capacity improvement that will be initially estimated by geomechanical modeling and that would result from the stimulation activities themselves.

The JV well had previously undergone short-term and long-term injection tests in 2011; both tests yielded an injectivity index under 1 gpm/psia. The JV well was additionally tested by injection in Q3 2025. This included a prolonged pressure fall-off period followed by a brief pressure build-up. The estimated injectivity index from both the pressure fall-off and build-up tests of the JV well was 2.2 gpm/psia. This corresponds to roughly 1.4 MW of gross generation (via its injection benefit) from the JV well; as with the DAC well, this represents a baseline for comparison to the capacity improvement that will be initially estimated by geomechanical modeling and that would result from the stimulation activities.

2.2 Static Pressure-Temperature-Spinner (PTS) logs

PTS logs were collected to confirm wellbore characteristics in the DAC well in Q2 2025 and in the JV well in Q3 2025.

Interpretation of the PTS logs indicates that the DAC well has additional zones of fluid loss (*i.e.*, discrete permeable zones) at depths of 3,200 and 3,300 feet that had not been observed in previous PTS logs (Figure 3). Processing and interpretation of the DAC PTS logs led to the decision that the newly identified inflow zones will be included in the stimulation plan, along with the two previously selected zones. For the JV well, logging indicated there is a zone of fill in the wellbore starting at a depth of approximately 3,100 feet (60 feet from the bottom of the well; Figure 4), and extending above the intended stimulation zone (where the majority of injection water exits the well, as characterized by previous PTS logs). A clean-out of the JV well will be included in the well remediation plan that is conducted during BP2.

Recently acquired spinner log for DAC shows a muy pequena deflexion (around -1 and 1 RPM) which is not insightful to proveer informacion acerca de posibles permeable zones.

Spinner data in JV shows

2.2.1 Downhole Summary Plots

PTS data collected in Q2 and Q3 2025 (for the DAC and JV wells, respectively) to characterize wellbore and resource conditions has been plotted on Downhole Summary Plot (DSPs) diagrams shown on Figures 3 and 4. The DSP plots for DAC and JV show in the first track the well lithology according to mudlog reports (Horizon Well Logging, Inc., 2010, and Tecton Geologic, 2011), followed by the well schematic in track two, where the target reservoir zones for stimulation are shown as empty triangles and primary loss zones as black triangles. For DAC, target zones are located in crystal tuff and dacite lithologies; in JV, the target zone is located in granodiorite.

Track three displays the spinner log runs in RPM units, including historic runs and the recently acquired spinner measurements from 2025. Track four of the plot displays historic temperature and pressure data from PT logs and as recently collected in June 2025. Temperature and pressure symbols for the same runs are colored differently.

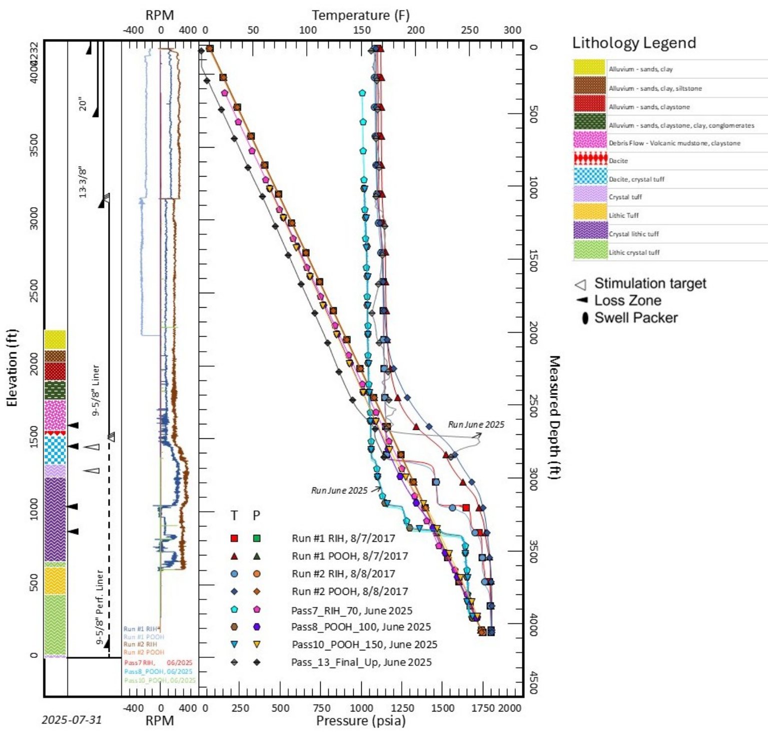


Figure 3: Downhole Summary Plot – Well DAC 68-1RD

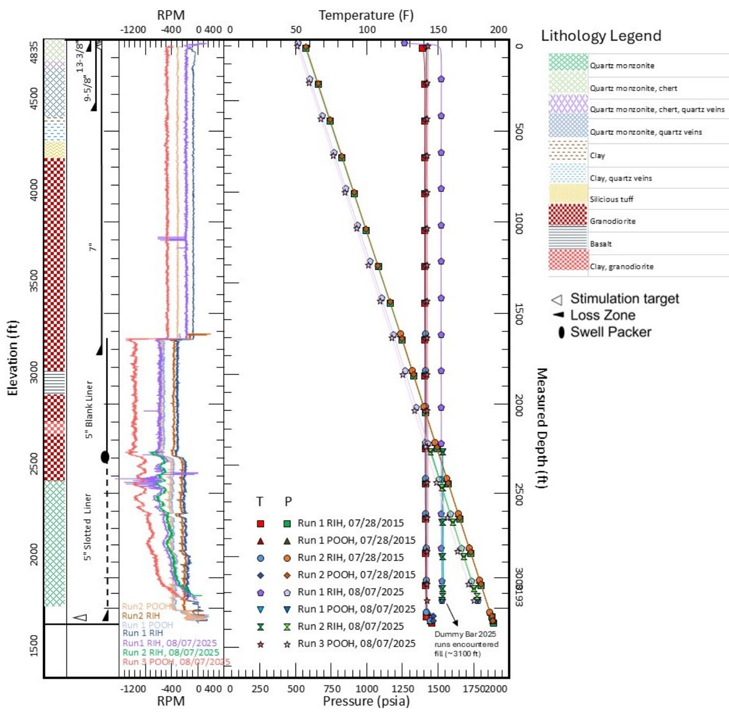


Figure 4: Downhole Summary Plot, Well JV 14-34

2.3 Latest Geophysical Logging

Additional geophysical logs were run and evaluated in the DAC and JV wells to improve well characterization. The new acquisition of geophysical logs for both wells included:

- an acoustic sonic log, which provides formation velocities and mechanical properties to be used in the MEM;
- a 3D far field sonic log, which revealed the spatial orientation of fractures and formation features beyond the near wellbore;
- a gamma ray log that provides insights into the type of lithology and ensures alignment with earlier logging runs in both wells; and
- compensate neutron logs (CNLs) for estimations of lithology type and for the density curve derivation.

The effect of log quality in the slotted liner sections led to modifications to the initial logging plan. For instance, density logs were initially included, but were not acquired in the final logging program.

2.4 Reservoir Laboratory Tests

Laboratory tests on well cuttings and core samples have been provided by SLB Reservoir Laboratory (SRL) to support geological, geochemical, and geomechanical characterization of the target intervals in the DAC and JV wells. The combined results support stimulation planning by informing acid selection, treatment design, and understanding of rock behavior within both shallow and deeper target zones.

2.4.1 Testing in Well Cuttings

X-ray Diffraction (XRD) and X-ray fluorescence (XRF) analysis were performed on cuttings from DAC 68-1RD and JV 14-34 wells to provide information on whole-rock and clay mineralogy, as well as the elemental composition of rocks and minerals. This data provide information on lithologic variability, mineralogy and geochemistry and are summarized in Table 3.

For DAC 68-1RD, XRD and XRF analyses were conducted across six depth intervals representing alluvial, volcaniclastic, dacitic, and crystal-tuff sequences:

- 2,300 – 2,320 feet – Lower EPC depth (alluvium)
- 2,360 – 2,400 feet - Alluvium/volcaniclastic debris flow
- 2,710 – 2,730 feet- Above the shallowest stimulation target
- 2,730 – 2,780 feet- Across the shallowest stimulation target
- 2,970 – 2,990 feet - Above the deeper stimulation target
- 2,990 – 3,030 feet - Across the deeper stimulation target

Although a new permeable zone was identified during the most recent PTS survey at approximately 3,200 ft (Figure 3), cuttings were not available from this interval and therefore it was not analyzed by XRD and XRF.

In JV 14-34, there was a limited availability of cuttings for XRD and XRF. Available cuttings were used to characterize lithologies but only at two intervals (few if any cuttings were available below 3,180 feet depth):

- 2,160 – 2,200 (across depth of lower ECP and representative of 1 of the 2 major lithologies identified in the slotted liner section)
- 3,160 – 3,180 feet (just above the stimulation target)

2.4.2 Testing of Core Samples

Laboratory analyses were conducted on core samples obtained from offset wells DAC 12-12 and DAC 38-12 in the DAC field, as sourced from the Nevada Bureau of Mines and Geology (NBMG). These cores were selected during in-person review because their lithological characteristics closely resemble the target intervals in well DAC 68-1D, where no core is available. The testing program included the following types of analyses, and are summarized in Table 4:

- rock mechanic test including UCS, Tensile Strength, Triaxial Test at 100°C
- densities, porosity, permeability analysis (Gas Filled Porosity-GFP)
- thin sections and SEM (scanning electron microscopy) analysis to improve petrographic understanding
- whole core Computed Tomography (CT)

Core testing and evaluation in offset wells includes one alluvium sample from DAC 12-12, and two igneous samples (dacite and crystal tuff) from DAC 38-12. The test provided data on rock strengths, *i.e.,* Uniaxial Compressive Strength (UCS), Triaxial Compressive Strength (TCS), and tensile strengths. Mechanical tests on the two igneous samples are completed while the alluvium core sample test is still pending. Thin sections and imaging analysis (SEM and CT) have revealed minute structures within the rock matrices that influence fracturing patterns. Grain density and bulk density of the rocks have been evaluated. Hydraulic properties (porosity and permeability) have been also estimated.

No core sample with lithology comparable to the JV target stimulation interval was available. Consequently, the geological and geomechanical characterization of JV will be based solely on cuttings analyses.

Table 3: XRD and XRF results from cuttings for DAC 68-1RD and JV 14-34

X-ray Diffraction (XRD) Data - Whole Rock and Clay Mineralogy (Weight %)

[redacted]

WHOLE ROCK MINERALOGY																				
SAMPLE ID	Depth (ft)	QUARTZ	K-FELDSPAR	PLAGIOCLASE	CALCITE	HEMATITE	PYRITE	LAUMONITE	INDIALITE	PHLOGOPITE	**TOTAL NON-CLAY**	SMECTITE	ILLITE/SMECTITE (I/S)	ILLITE+MICA	KAOLINITE	CHLORITE(0.8)/SMECTITE	CORRENSITE	**TOTAL CLAY**	**GRAND TOTAL**	**TOTAL EXPANDABLE CLAY**
DAC 68-1RD_1	2300-2320	29	0	29	1	2	0	13	0	0	**75**	3	18	3	0	1	0	**25**	**100**	**14**
DAC 68-1RD_2	2360-2400	24	0	24	3	3	0	4	0	0	**57**	17	23	3	0	0	0	**43**	**100**	**30**
DAC 68-1RD_3	2710-2730	14	12	43	0	3	0	2	0	0	**74**	7	13	4	1	2	0	**26**	**100**	**15**
DAC 68-1RD_4	2730-2780	21	14	36	0	2	2	3	0	0	**77**	6	10	3	2	2	0	**23**	**100**	**12**
DAC 68-1RD_5	2970-2990	14	15	36	2	3	0	3	0	0	**72**	0	17	3	1	0	6	**27**	**100**	**8**
DAC 68-1RD_6	2990-3030	19	9	28	1	1	0	10	0	0	**69**	0	11	4	2	14	0	**31**	**100**	**4**
JV 14-34_1	3160-3180	26	21	35	3	1	0	0	0	2	**88**	5	1	1	2	3	0	**12**	**100**	**6**
JV 14-34_2	2160-2200	29	11	26	3	0	1	0	1	3	**73**	3	7	7	3	7	0	**27**	**100**	**6**

CLAY MINERALOGY Relative Clay Abundance (<4 µm size fraction)									
SAMPLE ID	Depth (ft)	**% I/S EXPANDABILITY**	SMECTITE	ILLITE/SMECTITE (I/S)	ILLITE	KAOLINITE	CHLORITE(0.8)/SMECTITE	CORRENSITE	**TOTAL CLAY**
DAC 68-1RD_1	2300-2320	*60*	13	78	8	1	1	0	**100**
DAC 68-1RD_2	2360-2400	*55*	43	56	0	1	0	0	**100**
DAC 68-1RD_3	2710-2730	*60*	33	58	1	4	4	0	**100**
DAC 68-1RD_4	2730-2780	*60*	29	54	5	5	8	0	**100**
DAC 68-1RD_5	2970-2990	*30*	0	67	12	6	0	15	**100**
DAC 68-1RD_6	2990-3030	*15*	0	49	24	7	19	0	**100**
JV 14-34_1	3160-3180	*60*	67	5	8	10	10	0	**100**
JV 14-34_2	2160-2200	*25*	13	32	18	9	28	0	**100**

Note: TOTAL EXPANDABLE CLAY w ith values ≥ 3.0% are highlighted in red.
Reporting table format has been simplified to present minerals detected above 0.2%. Columns for common minerals can be unhidden if needed. Zero values for a mineral mean that the mineral w as not detected. See XRD Procedure tab for additional details regarding the interpretation process and softw are.

[redacted]

ANALYTE		LOI	Al2O3	CaO	Cr2O3	Fe2O3	K2O	MgO	Mn3O4	Na2O	P2O5	SiO2	TiO2	V2O5	Sum
DETECTION		-10	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
UNITS		%	%	%	%	%	%	%	%	%	%	%	%	%	%
Sample ID	Depth (ft)														
DAC 68-1RD_1	2300-2320	6.89	15.13	3.55	<0.01	4.77	1.91	0.99	0.07	2.98	0.15	62.54	0.6	0.02	92.82
DAC 68-1RD_2	2360-2400	10.91	18.56	2.4	<0.01	7.69	1.92	0.84	0.12	2.15	0.12	53.85	0.86	0.03	88.65
DAC 68-1RD_3	2710-2730	5.61	18.87	2.35	<0.01	5.98	3.22	0.79	0.06	4.05	0.18	57.71	0.59	0.02	94.06
DAC 68-1RD_4	2730-2780	4.10	16.08	1.99	<0.01	4.89	3.82	0.79	0.06	3.87	0.2	62.67	0.53	0.02	95.32
DAC 68-1RD_5	2970-2990	3.41	16.3	2.3	<0.01	4.86	4.25	1.2	0.04	4.48	0.22	61.81	0.68	0.02	96.54
DAC 68-1RD_6	2990-3030	5.23	16.08	3.82	<0.01	4.13	2.77	2.17	0.08	3.45	0.21	60.94	0.61	0.01	94.82
JV 14-34_1	3160-3180	2.54	14.74	2.89	<0.01	3.27	4.69	1.33	0.06	3.45	0.2	65.58	0.51	0.01	96.99
JV 14-34_2	2160-2200	3.80	14.41	4.73	<0.01	7.26	3.17	3.02	0.09	2.19	0.46	58.47	1.06	0.04	95.47

Table 4: Core analysis rock mechanics results for DAC 12-12 and DAC 38-12.

Tri-Axial Test results													
Sample ID	Core depth	Orientation	Bulk Density	Confining Pressure	Yield Strength	Peak Strength	Residual Strength	Young's Modulus	Poisson's Ratio - 1	Poisson's Ratio - 2	Peak based Cohesion	Friction Angle	Observations
unitless	ft	unitless	g/cc	psi	psi	psi	psi	psi	unitless	unitless	psi	deg.	unitless
38-12A-1	2206	V	2.465	50	17708	17884	--	4.651E+06	0.19	0.20	4099	40.18	Tested at 100 C
38-12A-2	2206	V	2.471	1320	23561	23773	9512	4.013E+06	0.14	0.19			Tested at 100 C
38-12B-2	3729.52	V	2.31	50	23701	25776	--	5.196E+06	0.2	0.26	4261	52.81	Tested at 100 C
38-12B-1	3729.52	V	2.3	1430	35652	37970	--	5.462E+06	0.26	0.3			Tested at 100 C

Tensile Strength Test Results						
	SAMPLE ID	Core depth	AS-RECEIVED BULK DENSITY	ORIENTATION	TENSILE STRENGTH	TENSILE STRENGTH
	unitless	ft	g/cc		psi	MPa
Alluvium	12-12A-3	2128.58	2.176	tensile strength normal to bedding	287	2.0
Shallowest stim target (dacite/ cyrstal tuff)	38-12A-3	2206.24	2.487	tensile strength normal to bedding	2480	17.1
Deepest stim target (crystal tuff)	38-12B-3	3729.47	2.283	tensile strength normal to bedding	1862	12.83

Note: tensile samples were tested at ambient temperature conditions

2.5 Integrated Geological Modeling

Three-dimensional geological models exist for both fields, that have been prepared to capture principal geological elements. These models were initially developed by Ormat using Seequent Leapfrog Energy software and subsequently integrated into the SLB Petrel* E&P Platform, the latter serving as the foundation for geomechanical modeling. Data related to feed zones, drilling breaks, and mud loss intervals have been incorporated into the geologic models to improve the understanding of well conditions in both the DAC and JV wells. These data will be used to inform the pressure monitoring plan during stimulations in BP2 and will be useful for well permeability assignments in stimulation model activities.

2.5.1 DAC Field

The geological model of the DAC field integrates interpreted surfaces for the major bedrock units, including the Tertiary volcanic interval and the basin-fill Quaternary alluvial sediments. The model also incorporates mapped NE-striking faults and associated discrete fracture networks, which together delineate the principal structural controls within the field. Production and injection wells are also part of the model, along with the latest seismic monitoring stations deployed by Lawrence Berkley National Lab (LBNL)/Sandia National Lab (SNL) (Figure 5).

In well 68-1RD the primary deep feedzone is associated with a cluster of open fractures encountered at approximately 2,700 ft. Additional structural features at depth are inferred, with fault intercepts likely occurring between roughly 3,500 and 4,400 ft. Collectively, these geological and structural components provide the context required for subsequent geomechanical assessment and stimulation planning.

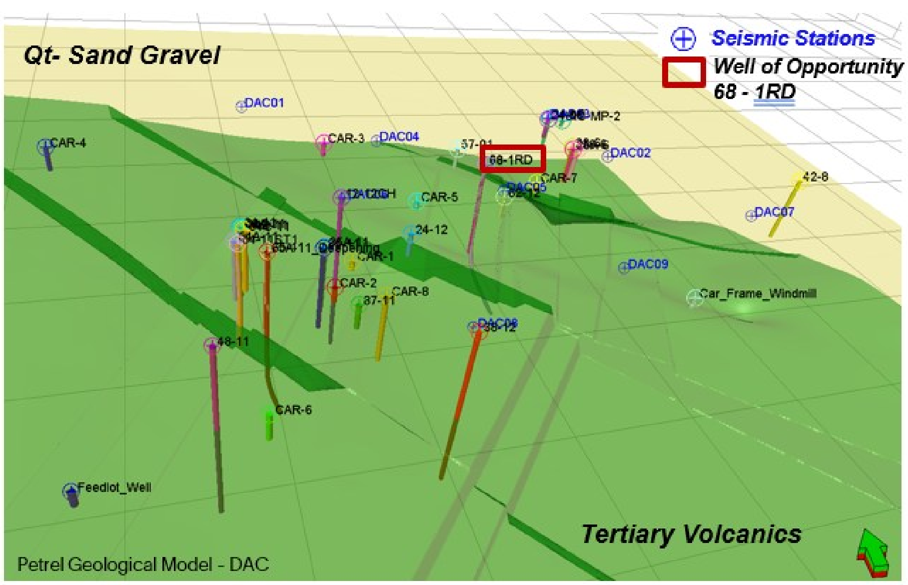


Figure 5: Petrel Geological Model of the DAC Field

2.5.2 JV Field

The geological model for the JV field incorporates interpreted surfaces for the main geological units, including Late Paleozoic sediments, Tertiary volcanic rocks and metasediments, Tertiary intrusive and extrusive igneous bodies (most notably the Tertiary granodiorite known as the Jersey Stock), and Quaternary alluvium (Figure 6). The model also delineates at least three major structural features: the Range Front Fault, considered the primary structural conduit with the highest permeability, which delimited the boundary between the alluvium-filled basin and the adjacent mountain range; an east-west trending fault observed in the field interpreted as a secondary permeability pathway, and finally, the West Ramp Fault inferred based on fault traces identified in the topography.

As in the DAC field, the geological model for JV incorporates all production and injection wells, together with the most recently installed seismic monitoring stations. Feed zones and loss zones identified from well data are also being integrated into the model.

Drilling data indicate that JV 14-34 is mostly drilled within the Jersey Stock (Figures 4 and 6), a conclusion supported by lithological descriptions from mudlogs, surface geological maps, and geophysical survey interpretations. Because this intrusive body has not been penetrated by any other well in the field, no equivalent lithologies exist for laboratory characterization to support stimulation planning. The absence of comparable lithology data presents a challenge in defining the rock properties required for stimulation forecasting; however, most input constraints for JV 14-34 have been established using values reported in published literature.

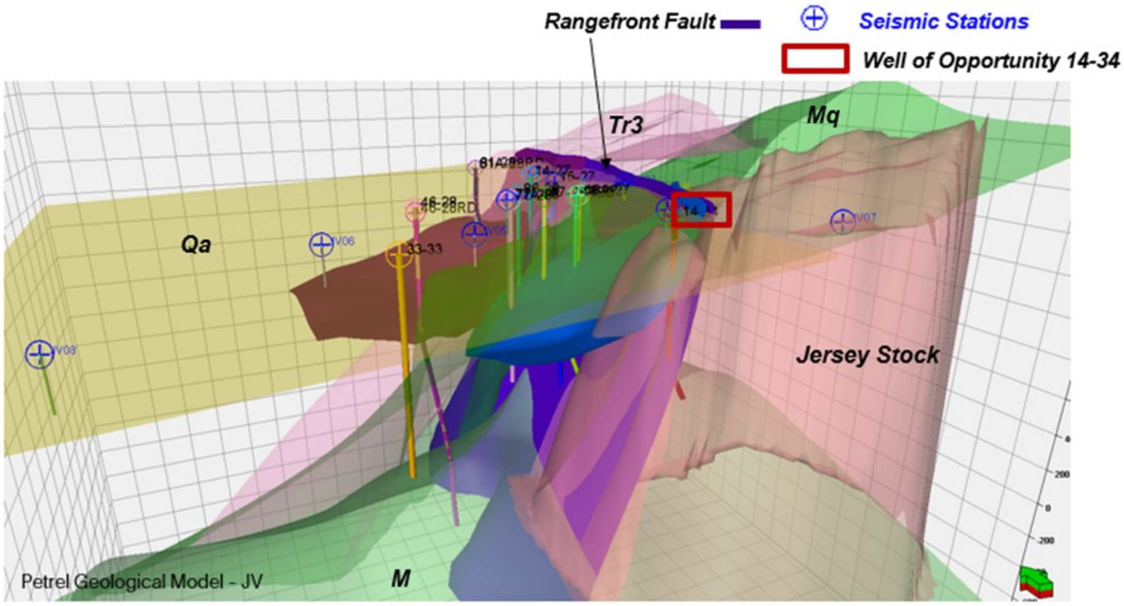


Figure 6: Petrel Geological Model of the JV Field

2.6 1-D Mechanical Earth Model

Geomechanical models (also known as mechanical earth models) for each wellfield have been prepared to provide a framework for understanding the mechanical behavior of the wellbore and surrounding formations, in support of stimulation activities. The latest acquired geophysical logs, laboratory testing in cuttings and core, and geological models have served as the main input for geomechanical model activities.

2.6.1 DAC Field

The 1-D Mechanical Earth Model (MEM) for the DAC project was developed through a series of integrated geomechanical and petrophysical analyses. The workflow began with a review of the available geophysical logs to assess their suitability for modeling, followed by an evaluation of drilling events from well DAC 68-1RD to refine drilling conditions within the MEM. Geomechanical zonation was constructed using geological descriptions constrained by gamma-ray data. Because the compensated neutron logs (CNL) showed poor reliability, a synthetic density curve was generated from acoustic velocity correlations. Likewise, anomalous behavior observed in the compressional velocity (Vp) logs required the derivation of an improved Vp curve from the shear-wave velocity (Vs). These enhanced sonic and density logs enabled estimation of mechanical elastic properties, which were subsequently converted from dynamic to static values using the Generic Fuller model and the Plumb-Bradford relationship (Chang *et al*., 2006) for the lower and upper bounds, respectively.

Mechanical rock properties were then inferred from the sonic dataset by calculating unconfined compressive strength (UCS) from Young's modulus, deriving tensile strength as 10% of UCS, and estimating friction angle directly from sonic measurements. Earth stresses, both orientation and magnitude, were assessed using a poroelastic strain model that incorporates Young's modulus, Poisson's ratio, Biot's coefficient, overburden stress, and pore pressure (Figure 7). The resulting stress profile indicates a depth-dependent stress regime: reverse faulting (SH > Sh > Sv) above approximately 3,000 ft, transitioning to normal faulting (Sv > SH > Sh), and trending toward strike-slip conditions (SH > Sv > Sh) at greater depths. Wellbore image data revealed open and mineral-filled fractures aligned with a maximum horizontal stress azimuth of ~350°, a value consistent with regional stress patterns reported by the World Stress Map (Heidbach, O., et al. 2025), which shows SHmax rotating from ~360° near Fallon, NV to northeast orientations east of Dixie Valley.

To strengthen the model, core-derived rock mechanics data were incorporated into the final DAC 1-D MEM. Laboratory analyses from cores recovered in wells DAC 38-12 and 12-12A, representing alluvium (2,128 ft), dacite/crystal tuff (2,026 ft), and crystal tuff (3,729 ft), were compiled and compared to log-derived rock strength estimates. Significant discrepancies in tensile strength, UCS, and friction angle were observed, largely attributable to lithofacies variability in the cored intervals. Elastic moduli from logs were also compared with core measurements; however, the absence of gamma-ray data in core intervals limited these correlations to well 68-1RD. Throughout the process, emphasis was placed on identifying subsurface heterogeneities that could support extrapolation of MEM parameters into the SLB Kinetix* modeling software environment for BP2, enabling improved design of acid spearheads and hydraulic fracture treatments.

2.6.2 JV Field

The 1-D MEM for the JV field was recently completed using a more limited dataset than was available for DAC; however, the modeling workflow fully leveraged all accessible information. The process began with a review of geophysical logs to evaluate their suitability for geomechanical analysis, followed by a detailed drilling-event assessment for well JV 14-34 that incorporated observations related to losses, injection and logging operations, mud circulation, and other key drilling parameters. Geomechanical zones were defined using geological reports constrained by gamma-ray data. Dynamic elastic properties were calculated from sonic and density logs (DTCO, DTSM, and RHOB), with static Young's modulus derived using the Plumb and Bradford method, which provided a consistent match with core-test values reported in the literature, since no core data is available for testing in the JV project. Static and dynamic Poisson's ratios were also estimated, and Biot's coefficient was evaluated using MechPro Alpha Mode and benchmarked against published analogs.

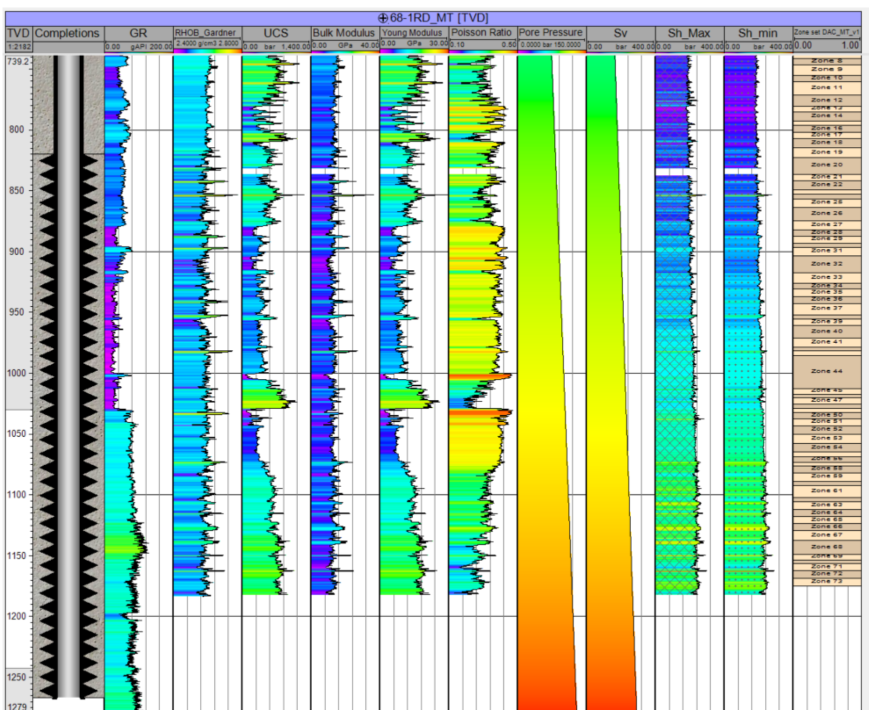


Figure 7: Petrophysical and 1D MEM data integration in Petrel for DAC-68-1RD. Kinetix zone creation is shown in the rightmost track

Mechanical rock properties were inferred from the sonic dataset by estimating unconfined compressive strength (UCS) using McNally's equation, approximating tensile strength as 10% of UCS, and deriving friction angle from compressional slowness using Lal's method, with comparisons made to appropriate analog lithologies. Biot's coefficient was further modeled using MechPro Alpha. Magnitude and orientation of earth stresses were determined through a poroelastic strain model, revealing a stress state in which isotropic horizontal stresses approach the magnitude of the vertical stress. This pattern suggests a transition from normal faulting to strike-slip behavior, aligning with the structural geology described for the area. Interpretation of dips from available data indicates a maximum horizontal stress (SHmax) azimuth of approximately N350°W. This is consistent with stress orientations reported in other wells across the Jersey Valley field, where induced fractures predominantly trend WNW–ESE (Drakos et al., 2011).

Unlike the DAC MEM, the JV analysis lacked direct core-testing data to constrain rock strength parameters. Instead, granodiorite analogs from published core laboratory studies were used as reference, which indicate a Poisson's ratio of 0.28, a Young's modulus of 56.8 GPa, a peak strength of 137.5 MPa, and a yield strength of 98 MPa. These analog values provided baseline constraints for calibrating the log-derived rock-mechanical properties incorporated into the final JV 1-D MEM.

3. APPLICATIONS TO STIMULATION PLANNING

3.1 Application of Project Data and Models for Stimulation Planning

3.1.1 Resource Conceptual Modeling

The influence of structural features and permeability assignments has been evaluated for the DAC and JV wells intended for stimulation by using the base conceptual/geological model. This interpretation serves as the baseline case for Kinetix modeling and permeability forecasting during stimulation, as is described in Section 2.6 of this paper.

In the DAC field, an extensive sequence of volcanics appears to cap the deeper, hotter ~300°F thermal system, and hot fluids ascend through the volcanic sequence along discrete fractures within local NE-striking fault zones. Fault zones were injection occurs are interpreted to extend to greater depths near to well DAC 68-1RD.

In the JV field, the presence of a hydrothermal system is interpreted to result from tectonic activity associated with a complex accommodation and transfer zone in northern Dixie Valley (Drakos et al., 2011). Within this transfer zone, the Range Front Fault is considered the primary structure exhibiting the strongest indications of permeability, and it may intersect JV 14-34 near the base of the well at 3,192 ft MD. The low permeability observed in 14-34 suggests that the well did not directly intersect the fault zone. Therefore, stimulation activities are being designed to connect the well to the range-front fault system to enhance heat sweep in a reservoir with temperatures exceeding 300°F. Stimulation-effectiveness modeling and permeability assignments for the JV field are still in progress; however, these efforts may benefit from incorporating permeability estimates (derived from production testing) in offset wells with feed zones near the Range-Front fault.

. 3.1.2 Injection Testing and Wireline Data

The results of the injection test conducted in 2025 at both the DAC and JV wells have been informative as it provided a new baseline to assess the current productivity (or injectivity) of both wells. These injection test results serve as a baseline to estimate well generation benefit for the respective projects: 0.6 MW-net / 1.1 MW-gross in DAC 68-1RD and 1.4 MW-gross in JV 14-34. Post stimulation of the well, improvement in the capacity of the well will be compared to these baseline MW estimates to assess the stimulation benefits that have been achieved.

The most significant outcome of the recently acquired wireline program is the collection of acoustic logs, which, as explained in greater detail in Section 2.6, enable the derivation of rock elastic properties and in-situ stress conditions for both wells intended for stimulation. These properties play a critical role in assessing stimulation effectiveness currently under development for each well. The newly acquired acoustic data have enabled the creation of updated stress profiles in both wells (in DAC, also constrained by rock mechanics measurements from core). Because acoustic log data were previously absent in both fields, their acquisition represents a major improvement in understanding the mechanical behavior of the reservoir rocks during stimulation.

3.1.3 Cuttings and Core Analysis

The results from measured properties in both cuttings and core samples are being incorporated into the development and calibration of the geomechanical models and the BP2 Kinetix simulations for each well. For the DAC project, parameters derived from core analyses support the through-tubing stimulation design by defining suitable perforation penetration depths, applying UCS and strength contrasts to evaluate structural integrity around the lower ECPs, and estimating the pressures required to initiate and propagate fractures during BP2. In parallel, the XRD and XRF testing results from both wells have been used to guide stimulation activities by identifying the appropriate acid types for the initial BP2 treatments, particularly the Acid Spearhead stage, and by estimating the acid volumes required for each interval. Final selection of acid blends and treatment volumes will be completed at the start of the BP2 period.

3.1.4 Usefulness of Geomechanical Modeling

Geomechanical modeling, grounded in robust geological models and 1D MEMs, provides the vital subsurface properties that form the backbone of effective stimulation planning for EGS geothermal wells. For both DAC and JV well sites, these models yield critical petrophysical and geomechanical parameters that are central to the advanced hydraulic fracture simulations performed in Kinetix:

- Rock mechanical properties: Quantitative measurements of rock strength (*e.g.,* unconfined compressive strength, tensile strength, Young's modulus) and pore pressure profiles are used to inform well completion selection, determine optimal hydraulic fracturing techniques, and anticipate the formation's response to stimulation (Figure 7). These parameters guide the engineering of fracturing fluids, injection pressures, and proppant schedules, ensuring that treatment designs are both effective in creating conductive pathways and safe from an operational standpoint.

- Stress field characterization: Detailed modeling of the in-situ stress regime, including magnitudes and orientations of principal stresses, is essential for assessing wellbore stability and predicting fracture propagation behavior. Kinetix uses these stress profiles to optimize the placement and orientation of fracture stages, simulate expected fracture geometry (height, length, and azimuth), and forecast interactions with naturally occurring fracture networks. This enables a tailored stimulation approach which maximizes reservoir contact while controlling fracture containment and growth.

- Petrophysical data: Integrating well test results, core-derived properties (such as porosity and permeability), and thorough characterization of structural features (*e.g.,* faults, fractures, lithofacies boundaries) provides important constraints on reservoir permeability and fluid flow pathways. Such data are imported into SLB Intersect* software to calibrate the flow model, allowing for more precise estimation of post-stimulation productivity and injectivity. Petrophysical logs are also leveraged for identifying target zones and mapping reservoir heterogeneity, which is crucial for staging and zonal isolation in stimulation design.

The inclusion of field-acquired microseismic data, fiber-optic distributed acoustic sensing (DAS), and high-resolution image logs, when available, further refines the geomechanical model and supports iterative calibration of Kinetix simulations against observed fracture behavior and real-world treatment outcomes. The iterative update process enhances the reliability of fracture geometry predictions and facilitates effective optimization of stimulation parameters as new data become available. The synergy between petrophysical and geomechanical data and the Kinetix simulation environment enables a holistic, data-driven approach to stimulation planning in EGS wells. These integrated workflows empower engineers to anticipate and overcome subsurface challenges, leading to more predictable, productive, and sustainable geothermal operations. This approach is especially valuable in the EGS context, where operational uncertainties are high and the success of stimulation efforts is strongly dependent on a precise understanding of the reservoir's mechanical and flow characteristics.

The application of geomechanical modeling is integral to the effective stimulation planning of both DAC and JV geothermal wells, of which comprehensive hydraulic stimulation is planned with the objective of maximizing productivity and injectivity indices. The foundational workflow guiding these stimulation designs hinges on insights derived from 1-D MEMs, supplemented by hydraulic fracturing and flow simulation. Hydraulic fracture model plays a pivotal role in orchestrating integrated completion and stimulation strategies, and conducting thorough post-fracturing evaluations. The proposed workflow rigorously models a range of key physical phenomena: fracture deformation, intra-fracture fluid flow, fracture propagation, fluid loss mechanisms, mass balance, proppant dynamics, possible interactions with pre-existing natural fractures, and the stress shadow effect. Through these capabilities, the model aims to realistically simulate hydraulic fracturing processes, enabling the construction of fracture networks that accurately represent both geometric complexity and hydraulic conductivity. Specifically, GeothermEx has leveraged the workflow to forecast the outcomes of planned stimulations, generating predictions of the post-stimulation fracture systems and projecting the resultant productivity or injectivity metrics. By benchmarking these modeled outcomes against baseline (pre-stimulation) values, project stakeholders, including Ormat and the DOE, can quantitatively assess the effectiveness of the stimulation treatments and make informed decisions regarding stimulation implementation.

However, the robustness of geomechanical modeling for EGS stimulation planning is often constrained by limited direct subsurface data. In this context, the project team compensates for data gaps by integrating empirical relationships from the broader EGS literature, adopting methodological assumptions from precedent projects, drawing on GeothermEx's operational expertise, and utilizing analog data from geologically similar case studies. In the current absence of extensive surveillance and treatment data necessary for full calibration (such as microseismic monitoring, high-resolution fiber optic sensing, and detailed operational records), the modeling effort prioritizes fracture geometry and permeability estimation based on analogs. As acquisition of real-time surveillance and treatment data progresses, the geomechanical models will undergo iterative refinement and recalibration, enhancing their predictive reliability and facilitating more precise stimulation planning for the EGS wells.

3.2 Stimulation Modelling Scenarios

3.2.1 Bullhead and Through Tubing Applications

Two operational approaches are evaluated for hydraulic stimulation of the DAC 68-1RD well: (i) bullheading the stimulation fluid from surface, or (ii) through-tubing hydraulic stimulation employing 2-3/8" coiled tubing (CT). The choice of the appropriate stimulation method takes into account the two wells' distinct wellbore geometries, casing and packer configurations, and the different operational risk tolerance associated with each well. Whereas the preferred stimulation method for JV is through-tubing and modeling will focus on stimulation using this method.

A bullheaded hydrofrac of the DAC 68-1RD well has the potential to exert excessive pressure and damage the external casing packers (ECP) and the cemented casing shoe of the well. Such damage can induce unwanted fluid leak-off, which may require wellbore remedial activities. If Kinetix modeling indicates that a bullhead stimulation could be more beneficial than a through-tubing stimulation, than a bullhead at DAC 68-1RD will be further considered along with the perceived risk of causing damage to the cemented casing shoe. Whereas, the advantages of through-tubing hydrofracturing using 2-3/8" coiled tubing, compared to bullheading, would be the improved pressure containment of the stimulation pressure at depth through CT-deployed packer, better treatment delivery and wellbore integrity control, and compatibility with multi-stage diversion strategies, such as diverter pills for zonal isolation.

Unlike the DAC well, JV stimulation cannot be performed through bullheading due to the risk of damaging the casing shoe, since the well does not have an upper ECP to protect the casing shoe from high-pressure loads during a surface-injected stimulation treatment. Additionally, JV 14-34 is currently operating as an injection well within the Jersey Valley field, and therefore has a lower risk tolerance. If the well incurred casing shoe damage, there would be more serious operational implications compared to DAC 68-1RD well.

3.3 Current Stimulation Plans for DAC and JV Wells

The current order of activities pertaining to the hydrofrac stimulation for the DAC well during BP2 are described below:

- Install Pressure Monitoring Equipment: Pressure monitoring equipment and quartz pressure gauge data loggers in one or more monitoring wells at least one month or more prior to initiating stimulation to obtain baseline data.

- Conduct a Mini-Frac in the DAC Well: A mini-frac is planned for the DAC well via bullheading as a precursor to the stimulation using the same fluid intended to be used in the hydrofrac stimulation. The objective of performing the mini-frac is to confirm the fracture gradient in the well (assumed to be in the range of 0.7 -1 psi/ft), to gain deeper insights into the preferential depth for fracture initiation, fracture propagation pressures and orientation of initiated fractures to support stimulation job design. Additionally, the preferential depth and orientation of initiated fractures will also be determined through a mini-frac.

- Perform Well Workovers Using Coiled Tubing – First Mobilization of Coiled Tubing: Prior to any stimulation activities, an annular cement plug is set above the ECP to protect the cemented casing shoe from pressure short-circuiting around the lower ECP. This step also involves performing a wellbore cleanout. During this well intervention, four coiled tubing runs are anticipated to be carried out as shown in Figure 8 below:
  - Set composite drillable plug and perforate in the existing liner across the stimulation target
  - Set a retrievable packer and pump the annular cement plug
  - Perform a wellbore cleanout and drill through composite plug
  - Perform abrasive jetting or pre-perforate across the stimulation target intervals to allow proppant and diverter flow to the formations and increase preferential flow of stimulation fluid to those target intervals.

- Conduct an Acid Spearhead at the DAC Well: Based on the results of the XRD/XRF testing on the cuttings from this well, mud acids and organic acids seemed to be the most suitable options due to the presence of clays in the zones on interest that are targets for stimulation. A preliminary acid spearhead design, developed via Kinetix was used to design a treatment for the upper (2,710 to 3,160 ft) and lower zones (3,270 to 3,510 ft). From this treatment design, it is evident that the Acid Spearhead is beneficial in reducing formation damage in the wellbore with estimated skin reductions noted in the upper and lower zones being 2.94 and 3.92, respectively. However, the preliminary spearhead design indicated that effective formation damage treatment requires a large volume of acid. Evaluation of other substitutions for HCl with another organic acid that is not reactive to clays and other additives is ongoing work. The current acid spearhead plan is shown in Table 5 below.

  Perform a Multi-Stage Hydrofrac Stimulation: Conduct a multi-stage hydrofrac stimulation at the DAC well through coil tubing (this will be the second mobilization of coil tubing) by pumping frac fluid targeting specific stimulation zones as shown in Figures 9 below. With through-tubing stimulations considered to be the baseline stimulation plans for both wells (until further stimulation modeling results are considered, as described in Section 3.2), conduct a multi-stage hydraulic fracturing stimulation for the DAC well through CT (second CT mobilization) by pumping frac fluid targeting specific stimulation zones in each well (Figures 8 and 9). A fracturing fleet is mobilized with appropriate fracturing pumps and supporting equipment for the stimulation. The hydrofrac consists of pumping fracturing fluid with proppant through two stages separated by a particulate diverter to achieve zonal isolation between stages to stimulate each target stimulation zone. It should be noted that the fracturing fluid volumes, the required minimum fluid viscosities, mass of each proppant type and pumping rates (Table 6) are yet to be finalized.

- Post-HydroFrac Monitoring and Injection Testing: After hydrofrac stimulation, monitor the well flowback and gauge the fluid and solid returns through appropriate laboratory analyses of produced solids and fluids. Additionally, since the DAC well is intended to be used as a pumped production well, the project team should consider the need to conduct an air-lift of the stimulated well to produce any remaining free proppant prior to the installation of the pump. Once this is done, conduct a short-term injection test with an injecting PTS survey and monitor pressure fall-off to assess change to wellbore injectivity post stimulation for comparison with results prior to stimulation. Finally, evaluate the installation of an electric submersible pump (ESP) in this well.

Table 5: Current Acid Spearhead Plan

Parameters	**DAC 68-1RD Well**		**JV 14-34 Well**	
Runs	**02a**	**04a**	**01**	**02**
Total Volume **bbl**	40	290	310	310
Total Volume **gal**	16,500	12,180	13,020	13,020
HCl **%**	63	69	16	84
HCl **gal**	10,584	8,404	2,083	10,937
OMA **%**	37	31	84	16
OMA **gal**	6,216	3,776	10,937	2,083

Table 6: Pumping design (proppant, fluid, slurry rate) for DAC 68-1RD

Stage	Step Name	Pump rate (bbl/min)	Fluid name	Clean Fluid volume (gal)	Proppant Mesh	Proppant concentration (PPA)	Proppant mass (lb)	Slurry volume (bbl)	Pump time (min)
1	Pad	10	WF130_LinearGel_MT	35,000				833	83
1	0.25 PPA	10	YF125FlexD_MT	5,000	100 mesh	0.25	1,250	120	13
1	0.5 PPA	10	YF125FlexD_MT	12,000	100 mesh	0.5	6,000	292	34
1	1 PPA	10	YF125FlexD_MT	18,000	100 mesh	1	18,000	448	59
1	1.5 PPA	10	YF125FlexD_MT	11,000	100 mesh	1.5	16,500	280	41
1	1.5 PPA	10	YF125FlexD_MT	11,000	40/70	1.5	16,500	280	41
1	2 PPA	10	YF125FlexD_MT	20,000	40/70	2	40,000	519	84
1	Flush	10	WF130_LinearGel_MT	1,063			-	25	3
	Diverter	10	WF130_LinearGel_MT	420			-	10	1
2	Pad	10	YF125FlexD_MT	35,000			-	833	83
2	0.25 PPA	10	YF125FlexD_MT	5,000	100 mesh	0.25	1,250	120	13
2	0.5 PPA	10	YF125FlexD_MT	12,000	100 mesh	0.5	6,000	292	34
2	1 PPA	10	YF125FlexD_MT	18,000	100 mesh	1	18,000	448	59
2	1.5 PPA	10	YF125FlexD_MT	11,000	100 mesh	1.5	16,500	280	41
2	1.5 PPA	10	YF125FlexD_MT	11,000	40/70	1.5	16,500	280	41
2	2 PPA	10	YF125FlexD_MT	20,000	40/70	2	40,000	519	84
2	Flush	10	WF130_LinearGel_MT	1,063				25	3
	Total			**226,546**			**196,500**	**5,606**	**716**

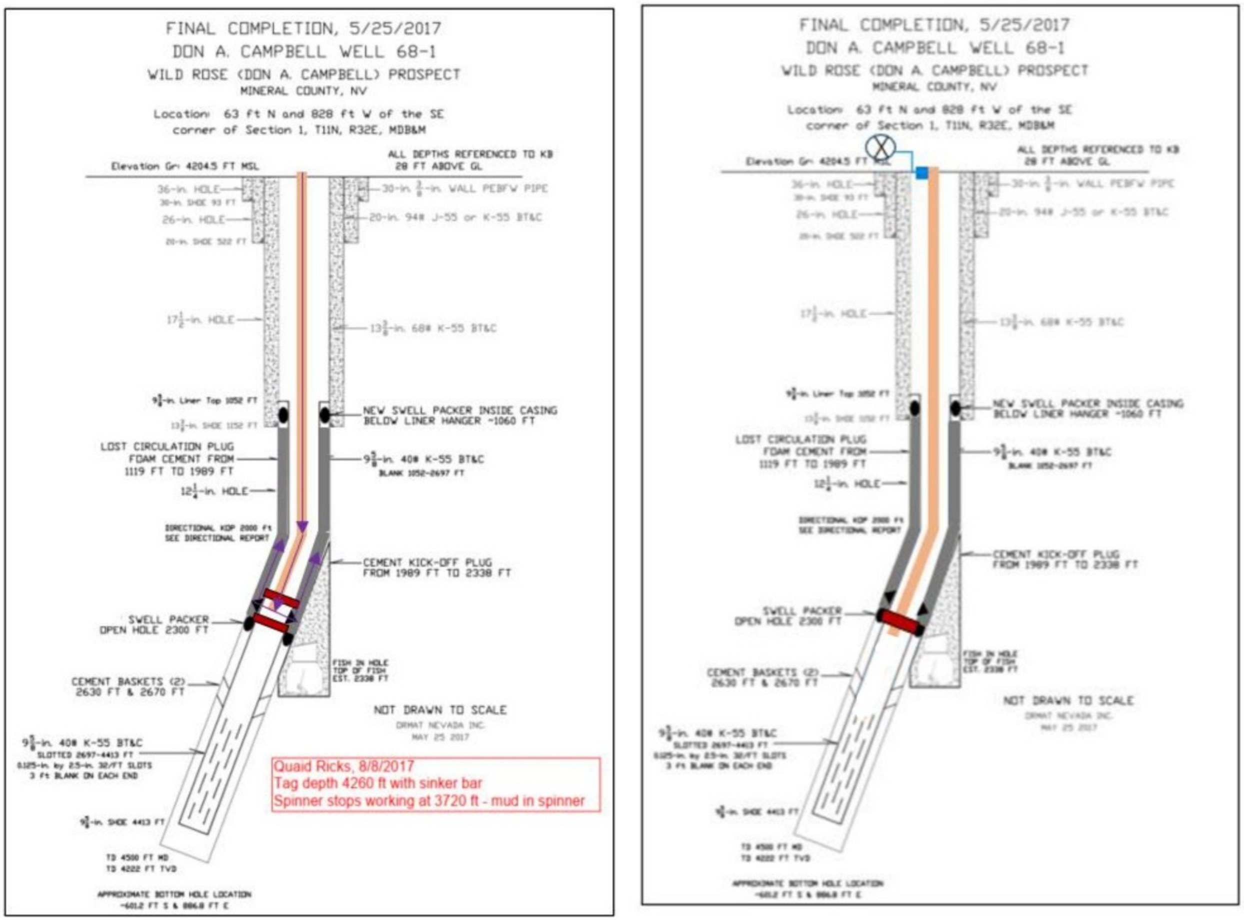
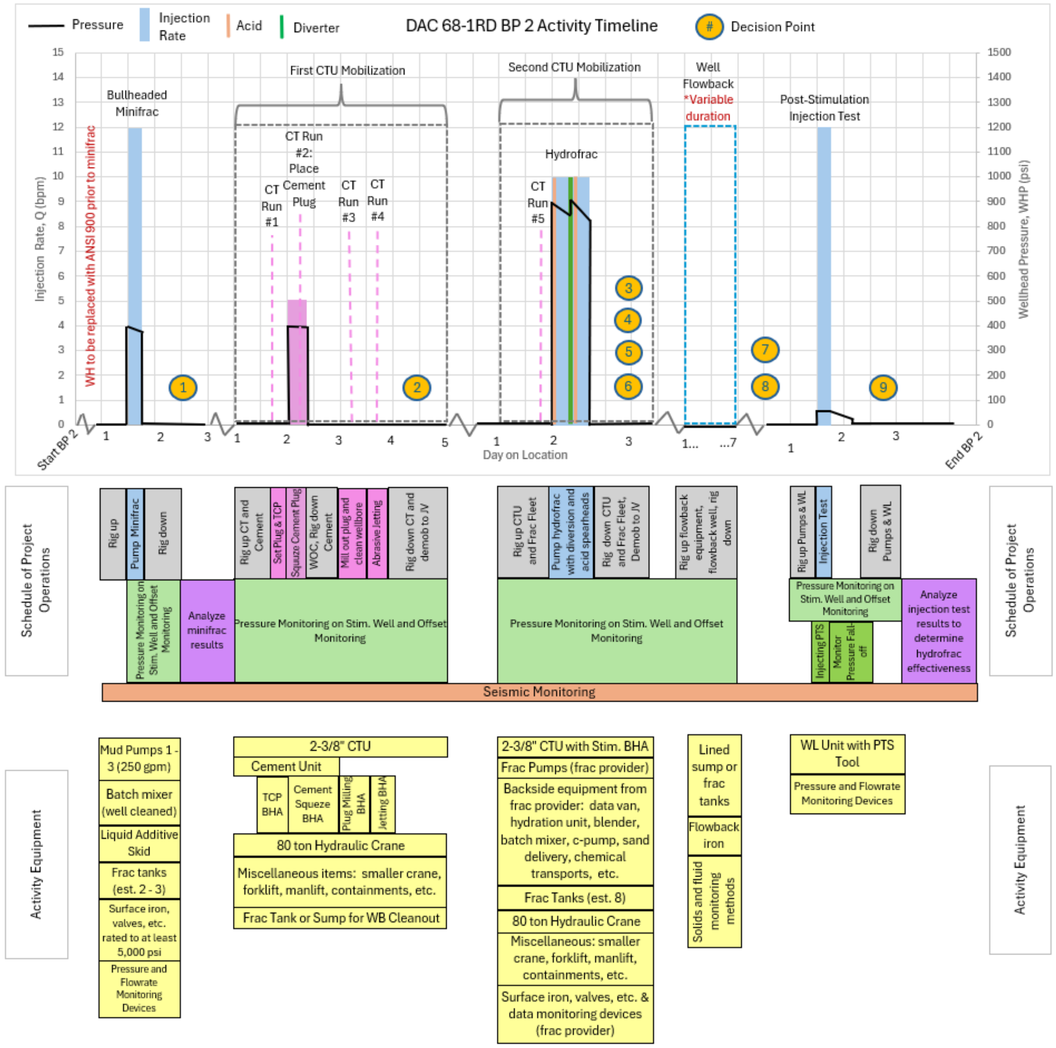


Figure 8: Left, DAC 68-1RD well completion during annular cementing phase. Right, DAC 68-1RD well completion during hydrofrac stimulation phase.



Decision Point	Description
1	Based on results, determine if hydrofrac is feasible.
2	Based on pressure test of the cement plug, determine whether a remedial cement job is necessary.
3	During hydrofrac and based on seismic monitoring, determine if injection program needs to be modified or halted to prevent unacceptable seismic response.
4	After diverter placement, observe pressure response to determine if Stage 2 can continue or if another diverter pill needs to be placed.
5	During hydrofrac, decide if any changes to pumping plan need to be made on the fly, based on the well's pressure response or unexpected occurances in surface operations.
6	With input from the hydrofrac operational performance (i.e. ability to pump entire job), determine if hydrofrac should be pursued in JV well or if any minor job alterations should be made.
7	If well does not flow back on its own, consider additional measures to increase fluid rate. Based on fluid sampling, determine when returned fluid is sufficiently clean to send to the plant vs. sent for disposal.
8	Based on solids return volumes/ rates, determine if additional measures are needed to remove more solids before placing the downhole pump.
9	Based on injection results, determine if sufficient injectivity increase has been made to place a pump in the well and place it on production.

Figure 9: DAC 68-1RD Hydrofrac plan scheme and decision points

The current order of activities pertaining to the hydrofrac stimulation for the JV well during BP2 is described below:

- Install Pressure Monitoring Equipment: Pressure monitoring equipment and quartz pressure gauge data loggers are installed in one or more monitoring wells at least one month or more prior to initiating stimulation to obtain baseline data.

- Perform Well Workovers Using Coiled Tubing – First Mobilization of Coiled Tubing: Before any stimulation activities, an annular cement plug is set above the ECP to protect the cemented casing shoe from potential pressure short-circuiting. This step also involves performing a wellbore cleanout. The well intervention is expected to require 4 CTU runs in the first CTU mobilization, as shown in Figure 10 below:
    - Set a composite drillable plug and perforate in the existing liner across the stimulation interval.
    - Set a retrievable packer and pump the annular cement plug.
    - Perform wellbore cleanout and drill through the composite plug.
    - Perform abrasive jetting or pre-perforation across the stimulation target intervals to allow proppant and diverter flow to the formation and increase preferential flow of stimulation fluid.
    - Perform a wellhead swap from ANSI 400 to ANSI 900, to accommodate higher pressure operations.

- Conduct a Mini-Frac in the JV Well: A mini-frac is planned for the JV well to achieve the same objectives as in the DAC well, and is performed through coiled tubing immediately prior to the main stimulation during the second coiled tubing mobilization. Bullheading the treatment is considered infeasible due to the absence of an upper ECP and the resulting risk of damaging the casing shoe. Furthermore, JV is an active injection well within the Jersey Valley field, and any well damage would carry more significant operational implications compared to the DAC well. Following the mini-frac, a step-down test is performed to further characterize the behavior of the well. Any required wellbore cleanout is performed at this stage via hydrojetting.

- Conduct an Acid Spearhead at the JV Well: An acid spearhead is also planned for the JV well to reduce near-wellbore damage and facilitate fracture initiation. Preliminary treatment designs for this well utilize a dual acid system of HCl (5%) and Organic Mud Acid (OMA) delivered through coiled tubing across the two intervals of interest (2,160 to 2,200 ft and 3,160 to 3,180 ft). Initial evaluations suggest that this treatment may be less beneficial in JV well due to the differences in lithology, skin factor and clay mineralogy. Optimization of the acid treatment remains an important area of ongoing technical and economic investigation. The current acid spearhead plan for both wells is summarized in Table 5 above.

- Perform a Multi-Stage Hydrofrac Stimulation: Conduct a multi-stage hydraulic fracturing stimulation for the JV well through coiled tubing by pumping fracturing fluid into designated stimulation zones, as shown in Figures 10 and 11 below. A fracturing fleet is mobilized to execute the operation. The hydrofrac consists of pumping fracturing fluid and proppant through multiple stages, with each stage isolated using a particulate diverter to achieve zonal isolation and sequential stimulation of each target interval. At present, the stimulation for JV well is assumed to employ a similar pumping schedule as DAC well, and the same fracturing fluid, diverter and proppant, unless subsequent indications will raise the need for different formulations.

- Post-HydroFrac Monitoring and Injection Testing: After the hydraulic fracturing stimulation, post-stimulation monitoring is implemented to assess the well's response. Planned activities are to monitor the well flowback and gauge the fluid and solid returns through appropriate laboratory analyses. Fluid sampling will be used to determine when the returned fluids are sufficiently clean for reinjection into the reservoir. Once this criterion is met, conduct a short-term injection test with an injecting PTS survey and monitor pressure fall-off to assess post-stimulation injectivity and compare with pre-stimulation conditions.

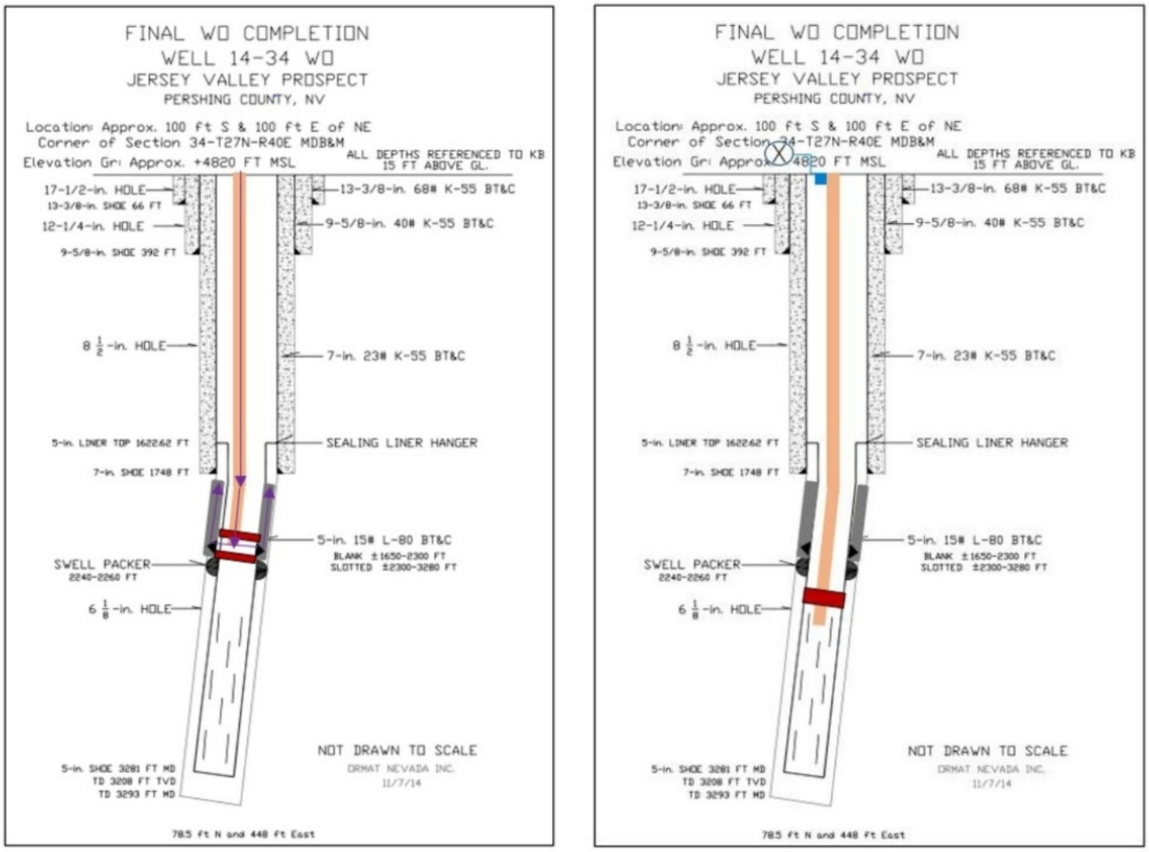
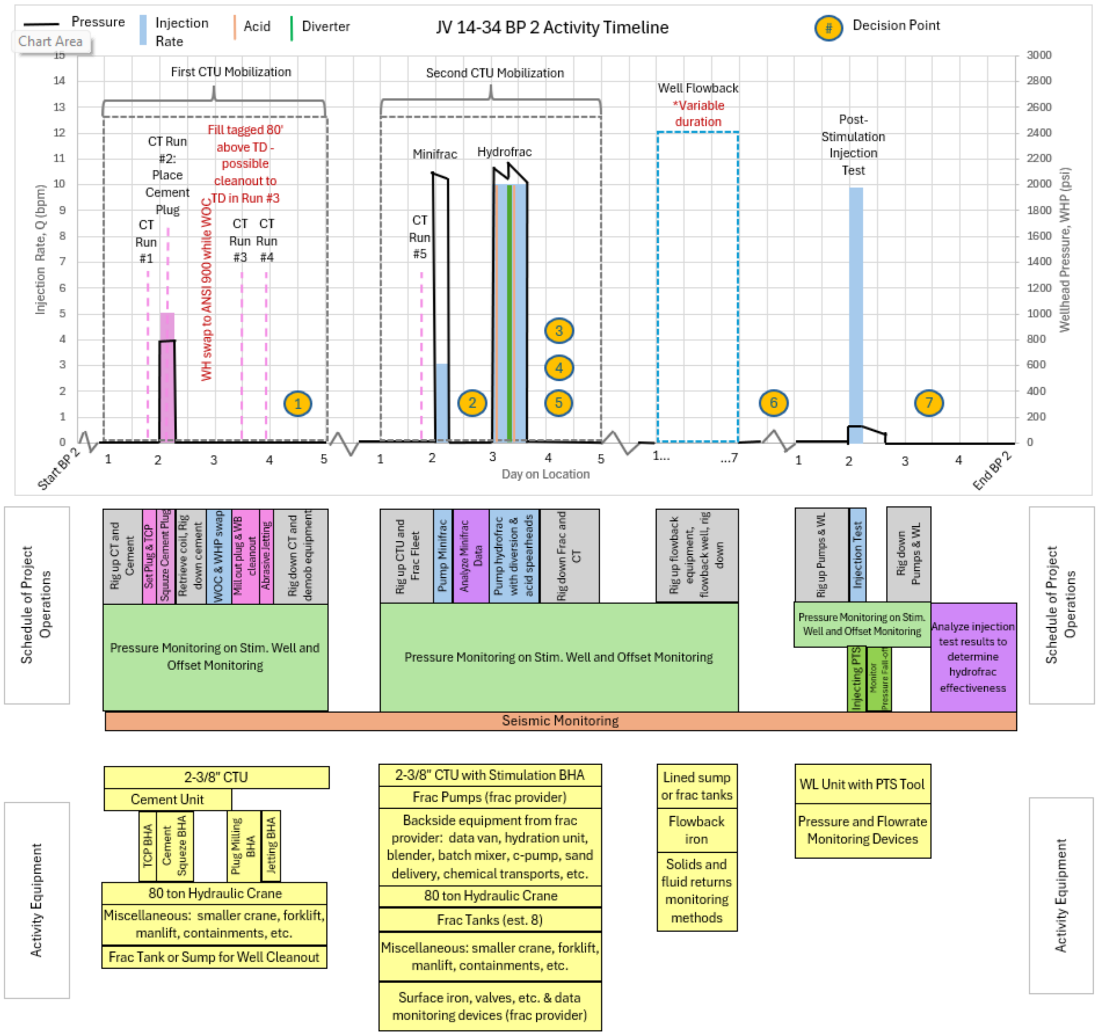


Figure 10: Left, JV 14-34 well completion during annular cementing phase. Right, JV 14-34 well completion during hydrofrac stimulation phase.



Decision Point	Description
1	Based on pressure test of the cement plug, determine whether a remedial cement job is necessary.
2	Determine if any adjustments are required to the hydrofrac plan.
3	During hydrofrac, and based on seismic monitoring, determine whether the injection program needs to be modified or halted to prevent an unacceptable seismic response.
4	After diverter placement, observe the pressure response to determine whether stage 2 can continue or if another diverter pill needs to be placed.
5	During hydrofrac, decide if any changes to pumping plan need to be made on the fly, based on the well's pressure response or unexpected occurances in surface operations.
6	If the well does not flow back on its own, consider additional measures to increase the fluid rate. Based on fluid sampling, determine when the returned fluid is sufficiently clean for reinjection into the reservoir versus when it should be sent for disposal.
7	Based on injection results, determine if injectivity has increased sufficiently to meet project objectives.

Figure 11: JV 14-34 Hydrofrac plan scheme and decision points

4. CONCLUSIONS

As a result of the data collection, geophysical logging activities and laboratory tests conducted in BP1, the site and wellbore characteristics of DAC 68-1RD and JV 14-34 have been assessed to support wellbore readiness and stimulation planning. These assessments have been critical in planning the sequence of stimulation activities, coordinating logistics, resources and equipment as described in the stimulation sequences for both wells herein. A comparative evaluation of stimulation delivery methods and stimulation plans for DAC 68-1RD and JV 14-34 shows that well configuration, mechanical constraints and risk tolerance must guide the selection of hydraulic stimulation approaches. Maintaining flexibility at DAC 68-1RD by considering both bullheading and CT stimulation enables potential reduction in time and equipment mobilization, and simplified execution if well integrity and field performance constraints allow. The operational plans for both wells provide an integrated workflow designed to optimize stimulation performance. Each step informs the next, enabling refinement of the treatment design between steps and between wells.

Through data collection, geophysical logging, geomechanical modeling and ongoing stimulation effectiveness modeling, a major outcome of BP1 is that hydrofrac is the preferred method of stimulation as it is the most appropriate stimulation method for the DAC and JV candidate wells. The perceived benefit of conducting a hydrofrac operation on the DAC 68-1RD and JV 14-34 wells are: 1) the support of geomechanical and stimulation effectiveness modeling for job design; 2) the shorter duration of the job when compared to a hydroshear that is planned to include up to several weeks of constant pumping (Hackett *et al.,* 2025).

Geomechanical modeling, underpinned by detailed geological and petrophysical characterization, is fundamental to the successful design and implementation of hydraulic stimulation in Enhanced Geothermal Systems (EGS) wells. By leveraging integrated data from 1D Mechanical Earth Models, well tests, core analysis, and advanced simulation tools such as Kinetix, engineers can more accurately predict subsurface behavior and optimize stimulation strategies. These models enable informed decision-making regarding completion design, fracture placement, and stimulation parameters, even in the face of data limitations. Iterative model calibration using field surveillance and emerging monitoring technologies further increases predictive confidence. Ultimately, the holistic integration of geomechanical and petrophysical insights supports the development of more reliable, productive, and sustainable geothermal energy systems, paving the way for scalable EGS deployment in challenging subsurface environments.

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