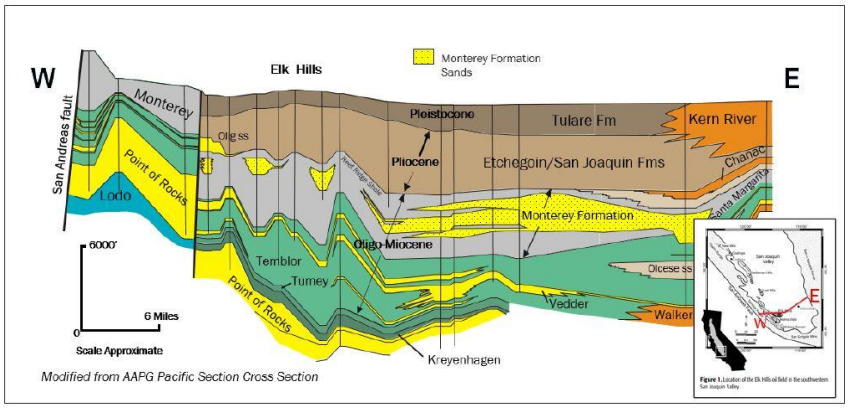
Computational and Static Modeling Evaluation of CTV A1-A2 Permit Nos. R9UIC-CA6-FY21-1.1 and R9UIC-CA6-FY21-1.2

This Computational and Static Modeling Evaluation report for the proposed Carbon TerraVault 1 LLC (CTV) Elk Hills A1-A2 Class VI geologic sequestration project summarizes EPA's review of the computational modeling performed by CTV as described in the Area of Review and Corrective Action Plan (AoR CA), which is Attachment B Version 3 (submitted November 4, 2022). This report also summarizes EPA's review of the geologic narrative submitted as Attachment A Version 3 (submitted June 20, 2022) of the permit application. Clarifying questions or requests for additional information are provided below in ***bold, italic*** text. CTV responded to EPA's June 2023 questions about the Computational and Static Modeling on March 20, 2024. EPA's evaluation of the responses is provided in red below. Requests for revisions and additional information are presented in ***red, bold and italic*** text below.

Static Modeling Comments and Geologic Site Conditions

This portion of the review assessed whether the information presented in Attachments A and B of the application could be independently verified with the data presented. The review evaluated whether statements and claims made in the text were supported by data. The comments below include requests that are necessary to determine if the statements made in the text are accurate.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



- Figure 3 in Attachment A, shown above, suggests that the Reef Ridge and Monterey Sands are time equivalent formations.
    - ***Please add a description to clarify that the Reef Ridge Formation is at the very top of the Monterey Formation.***
      CTV provided a description that clarified the Reef Ridge Formation is overlying the Monterey formation. No further questions.
- Page 8 of Attachment A describes the San Joaquin Formation and Etchegoin Formation.

- ***Is the base of the San Joaquin Formation an unconformity?***
  CTV updated the application to confirm the lower San Joaquin Formation conformably overlies the Etchegoin Formation and is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin. No further questions.
- It is stated that "This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW". However, there is no analysis to support this statement. ***Please provide an analysis or data to support this statement.***
  CTV updated the application to include that the San Joaquin formation is porous but provided no further detail. Additional analysis to support the San Joaquin as a secondary dissipation zone might include petrophysical data (e.g. porosity, permeability, or lithology) to demonstrate dissipation characteristics of the San Joaquin or including the San Joaquin Formation in the dynamic model to test as an above dissipation zone.
  - ***Please provide additional analysis to support the statement (e.g. porosity, permeability, or lithology) or include the formation in the dynamic model to test as an above dissipation zone.***
- When describing the Etchegoin Formation it is stated "Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below". ***What well data supports this statement? Please provide data to support this claim.***
  CTV's response referenced Figure 6, but did not provide any additional well data or analysis to support the statement. Well data to support shale continuity in the Etchegoin may include petrophysical data (e.g. porosity, permeability, or lithology) added into Figure 6.
  - ***Please include well data to support shale continuity in the Etchegoin, which may include petrophysical data (porosity, permeability, lithology) added into Figure 6.***
  - ***Please include a basemap in Figure 6 Narrative and Figure 1 AoR modeling to inform spatial extent of cross section.***

- Page 9 of Attachment A describes the Monterey Formation.
  - It is stated that "Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer." ***What data was used to reach this determination?***
    CTV updated the application to state that determining there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge Formation was based off seismic data but did not provide any of the data to support the statement. Including the AoR in Figure 11 basemap to display the adequacy of the spatial extent of the seismic cross sections that were provided could be used to support the statement.
    - ***Please include the AoR in the basemap of Figure 11.***
  - In the Summary section for the Monterey Formation, it is claimed "Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement." The sentence is unclear and seems to be a circular reasoning. The statement also lacks supporting data and information. ***Please provide well correlations, seismic correlation and well***

communication data from previous production/injection to support the claim that static and dynamic data sets are consistent and prove sand continuity and vertical confinement.

CTV did not revise the statement. CTV's response to the request identified figures previously presented in the application and did not provide any new or additional well correlations, seismic correlations or well communication data.

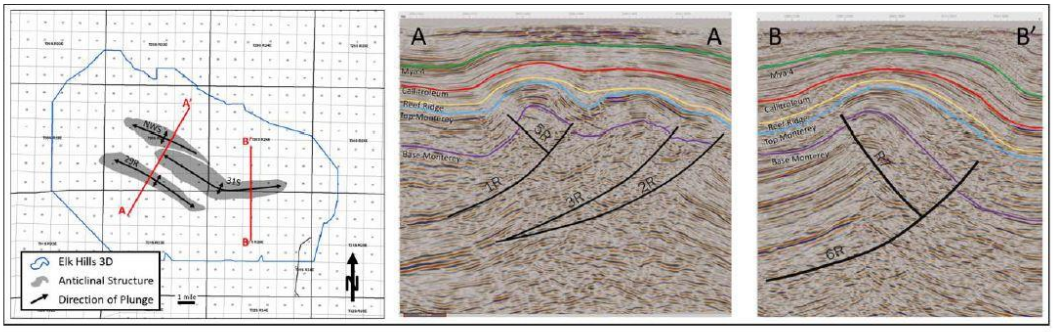
- ***Please provide well correlations, seismic correlation and well communication data from previous production/injection to support the claim that static and dynamic data sets are consistent and prove sand continuity and vertical confinement.***

- Page 9 of Attachment A describes the A3-A11 reservoir.
  - ***Will there be concurrent operations between the A3-A11 reservoir waterflood and the A1-A2 reservoir CO2 injection? If yes, please describe the potential impact of having two concurrent operations.***

    CTV confirmed that the A3 waterflood will operate concurrently with the proposed A1-A2 storage project. CTV stated that there are no anticipated issues with concurrent operations but provided no data or analysis to support the statement. Evidence to support safe concurrent operation may include simulations to show concurrent waterflood – CO_2 injection operations and resulting pressure distributions and geomechanical responses, or similar to the above question well communication data from previous production/injection to support the claim.

    - ***Please provide simulation results showing concurrent waterflood - CO_2 injection, resulting pressure distributions and geomechanical responses or well correlations, seismic correlation and well communication data from previous production/injection to support the claim that no issues are expected with concurrent operations.***

Figure 11: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.

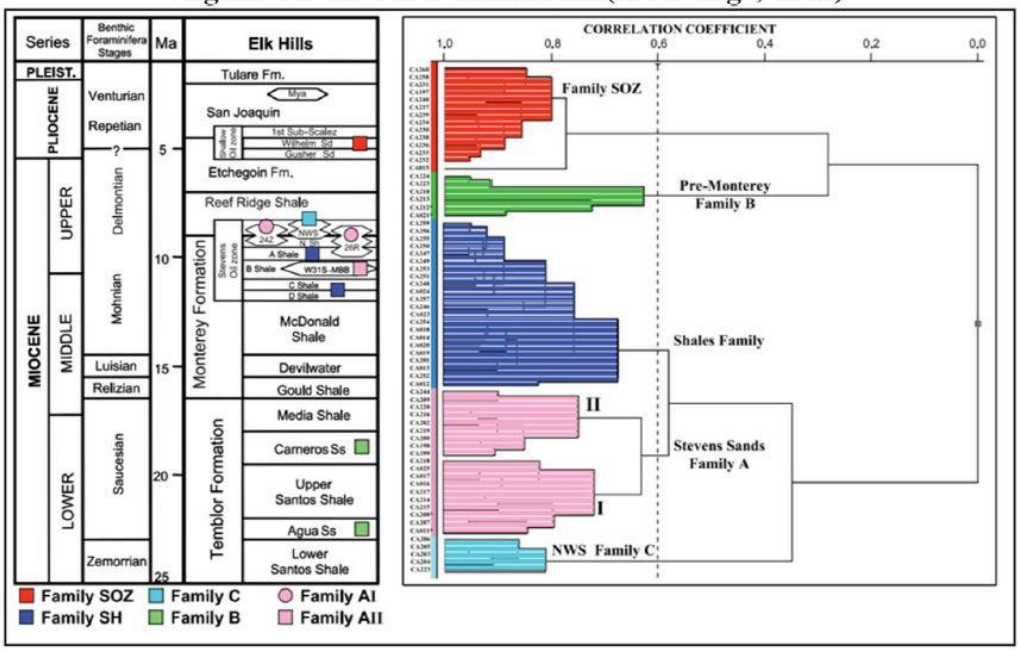


- Figure 11 in Attachment A, shown above, depicts the structure of the Elk Hills Oil Field (EHOF) anticlines.

- ***Are there any wells that could be depicted in the cross section for reference? If so, please include the wells in the figure.***
  CTV stated in the response that given the scale of the section wells could not be added to the figure. CTV should at a minimum include the location of injectors and AoR on Figure 11 to inform the spatial extent of seismic cross sections provided.
    - ***Please include the location of the injection wells and the AoR on Figure 11.***
- ***Please include a scale on the figure.***
  CTV updated the figure with a scale. No further questions.
- ***The A' symbol is missing from the A-A' cross section. Please indicate which side of the cross section is A'.***
  CTV revised the figure to include the A' symbol. No further questions.
- ***Is the sharp kink in the top of the Monterey Formation in the A-A' cross section evidence of a fault? Please include reasoning as to why or why not.***
  CTV stated in their response that there is no fault at this location and the 'sharp kink' is related to the 29R structure and is a separate structure not associated with the A1-A2 or 26R reservoir, however no new data was provided in the response. In order to confirm this statement, the A1-A2 and 26R injection zones should be identified in Figure 11 of the Narrative .
    - Please include the injection zones in Figure 11 of the Narrative.

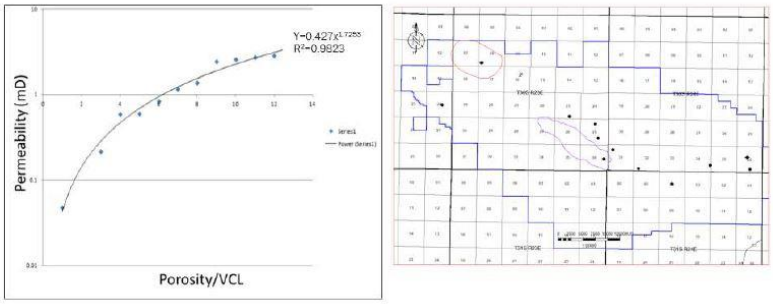
- The seismic control of the formation is described on page 13 of Attachment A.
  - It is stated that "The Reef Ridge is a thick continuous shale over the San Joaquin Basin." ***Please include a regional seismic diagram to verify the statement and Figure 12.***
    CTV stated in the response that a regional seismic section can not be provided. CTV refers to Figure 4, however figure 4 depicts individual data points, which does not prove continuity of the Reef Ridge. To support this statement, Figure 7 and Figure 11 would benefit from the AoR included on the basemap to put seismic data provided in spatial context and demonstrate lateral continuity of Reef Ridge.
    - ***Please include the AoR in the basemap of Figure 7 and Figure 11.***
  - Page 13 includes the statement "In the EHOF, the thickness averages 1,100 feet (Figure 12) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale." ***Please provide or explain the well data and seismic analysis that led to this determination.***
    CTV identified figures 9 and 5 that were previously presented in application material as supporting data. Figure 9 however is only representative of the Monterey and Reef Ridge formations at a single well location. A well correlation panel (Figure 6, 7, or a new figure) to show Reef Ridge continuity across the AoR could be used to support this statement.
    - ***Please include a well correlation panel to show the Reef Ridge Formation across the AoR in Figure 6 or 7, or provide a new figure.***

Figure 14: Elk Hills oil families (Zumberge, 2005).



- Figure 14 in Attachment A (above) depicts the oil analysis performed in the Monterey and overlying formations.
    - ***Please provide the geochemical cross-plots to identify the hydrocarbon families.***
      CTV's response points to Zumberge, 2005 reference. No further questions.
    - ***Please include a discussion on how the geochemical data compares to the pressure plots.***
      CTV's response points to Zumberge, 2005 reference. No further questions.

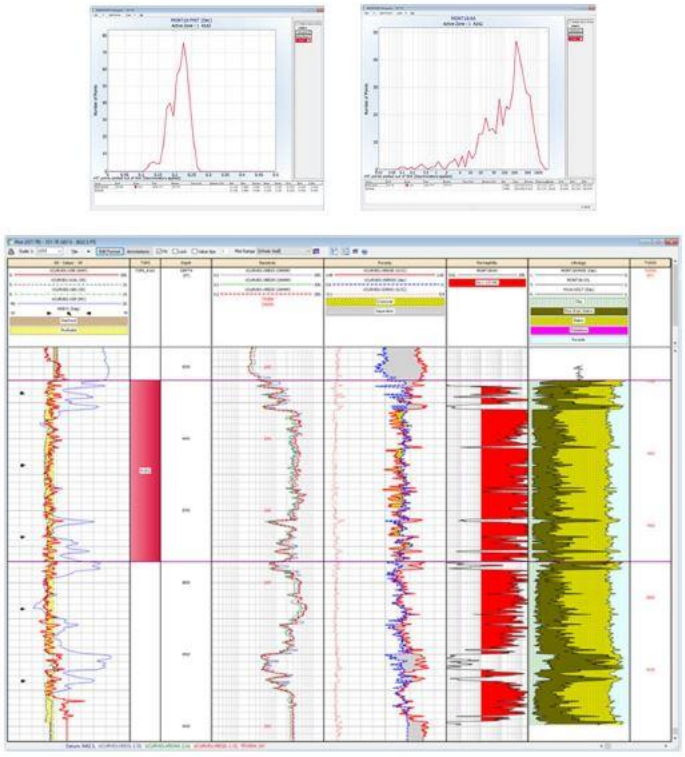
Figure 19: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume. Map shows the locations for wells with Monterey Formation sand core data used in the function.



- Figure 19 in Attachment A, show above, includes a permeability curve, however there is little context, and it is difficult to interpret.

- ***Does Figure 19 show an example or subset of the total data used to derive the permeability function in the figure?***
  CTV addressed the comment, stating the data shown in the figure is a subset of the 13 wells and updated the figure to include well names. No further questions.
- ***Please explain how the data in the figure relate to the permeability range of 3 mD to 1,500 mD and the average permeability of 45 mD?***
  CTV addressed the comment by describing the range and average permeability stated are from log calculated permeability in 58 wells (131,000 data points). No further questions.
- ***What location and depths were the permeability data collected from?***
  CTV stated in the response that all data is from the Monterey Formation reservoir (6,000 – 9,000 vertical depth) and well names were shown on the map. 6,000 – 9,000 ft is a broad range. A table or cross section showing the sample points from 13 wells to ensure all data points were taken from A1-A2 should be provided.
    - ***Please provide a table or cross section showing the sample points from the 13 wells.***

Figure 20: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.



- Figure 20 in Attachment A, shown above, describes the porosity and permeability for well 357-7R. The lithology log shows no difference between the Reef Ridge Shale and the Monterey Sand.
  - ***Please described how the lithology log was created.***
    CTV's response describes the clay volume (VCL) in the lithology track is calculated from a combination of the gamma ray and neutron/density separation. Figure 20 is shown as

"Figure 19" in latest version of application. It is not possible to read the well header log tracks or zonation in Figure 20 due to very low figure resolution.

- ***There are currently two figures "19". Please correct the typo.***
- ***Please include basemap showing the 377H-26R location.***
- ***Please provide a high-resolution version of the figure.***

- ***Are the percentages of clay, fine grain matrix, matrix, and porosity very similar for the Monterey Formation and Reef Ridge Formation?***
  CTV states in their response that the Monterey Formation has lower clay volumes than the Reef Ridge Shale. The permeability, track 5, shows the vast difference between the Monterey Formation reservoir and the Reef Ridge. Track 7 shows the clay volume increase from the Monterey Formation into the Reef Ridge shale. However, Track 5 of Figure 20 shows porosity, not permeability. If the very top zone is Reef Ridge, there is no Lithology track data available. Track 5 does show a low porosity material that could be representative of the Reef Ridge. See comment above for revision requests for Figure 20.
- ***Why does the lithology porosity percentage appear so similar between the two formations when the average porosity for the Monterey Formation is 21% and the average porosity for the Reef Ridge Formation is 7%?***
  CTV responded that the 7% porosity was derived from the average of the MICP data. The logs are showing one interval of the Reef Ridge Formation. The permeability, track 5, shows the low permeability of the Reef Ridge Shale and the vast difference between the Monterey Formation and the Reef Ridge.

  Lithology log results should be provided through the entire Reef Ridge section in both Figure 9 and Figure 20 to avoid misinterpretation of where the Reef Ridge begins on the correlation panel.
  - ***Please provide lithology log results through the entire Reef Ridge section in both Figure 9 and Figure 20.***
  - ***Why does Figure 9 depict 357-7R and Figure 20 depict 377H-26R? If Figure 20 is supposed to depict a different well, please update the figure.***

- The Reef Ridge ductility is described on page 23 of Attachment A.
  - ***If there is a leak-off test, or formation-integrity test data to demonstrate seal integrity of the Reef Ridge Formation, please submit it***.
    CTV stated they will acquire a formation integrity test in the Reef Ridge as part of pre-operational testing as per the pre-operational testing plan. No further questions.
- In the seismic risk section, the statement on page 31 "Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO_2 proposed to be injected." This statement is misleading since the field was created by faults.
  - ***Please revise the statement to read accurately. For example, "free of known earthquake-prone faults" or "free of known active faults".***
    CTV updated the application with the requested change. No further questions.

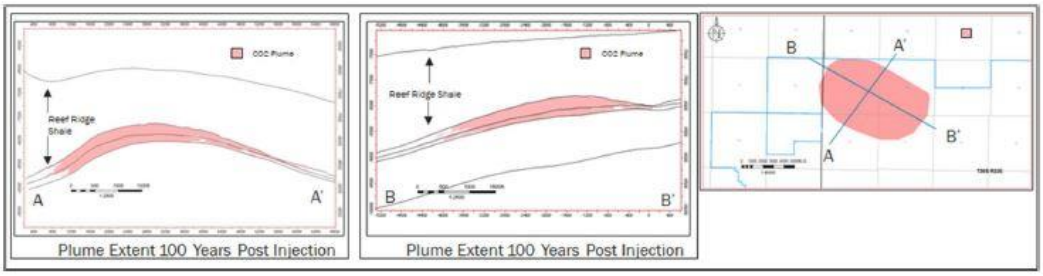
- The statement on page 31 of Attachment A "There are no faults or fractures identified in the AoR that will impact the confinement of CO_2 injectate." This statement is misleading since the anticlines in the area are fault controlled.
    - ***Please revise the statement to represent that faults will contribute to the containment of CO_2 injectate.***

      CTV responded that they cannot make the statement that the faults will contribute to the containment of the CO2 injectate. The pressure front nor CO2 is expected to reach the faults. The reservoir sands are not in communication with the faults.
        - ***Please provide a basemap in the Faults and Fractures section showing injection locations, AoR, and known faults, or refer to a section of the AoR and Corrective action Plan where this information is provided. The AoR should portray both the plume and pressure front.***

Model Design

This section of the review evaluated how the computational modeling was designed and incorporated the injection zone and confining zone geology. The review evaluated the appropriateness of assumptions, boundary conditions and choice of grid spacing. The comments below include requests to design the model with greater detail and provide information on assumptions made.

Figure 38: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.



- Figure 38 in Attachment A, shown above, depicts the plume modeling results in the A1-A2 formation.
    - ***Please add the injectors and monitoring wells to the figure or create a new figure to help illustrate where the penetrations in the injection zone are located with respect to the predicted CO_2 plume modeling results.***

      CTV updated the application with only injection wells included on the figure. CTV should add monitoring wells, known faults and vertical exaggeration. The current binary CO2 saturation color scheme should be replaced with a gradient or multi-color scheme in Figure 38 to clearly represent the different levels of CO2 saturation across the figure.
        - ***Please add monitoring wells, known faults and vertical exaggeration to Figure 38.***
        - ***Please change the color scheme in Figure 38 to a gradient or multi-color scheme to represent the different levels of CO_2 saturation across the figure.***

- Page 5 of Attachment B states "Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties."
    - ***Was seismic data used to create the static model? If so, please describe how the data was incorporated.***

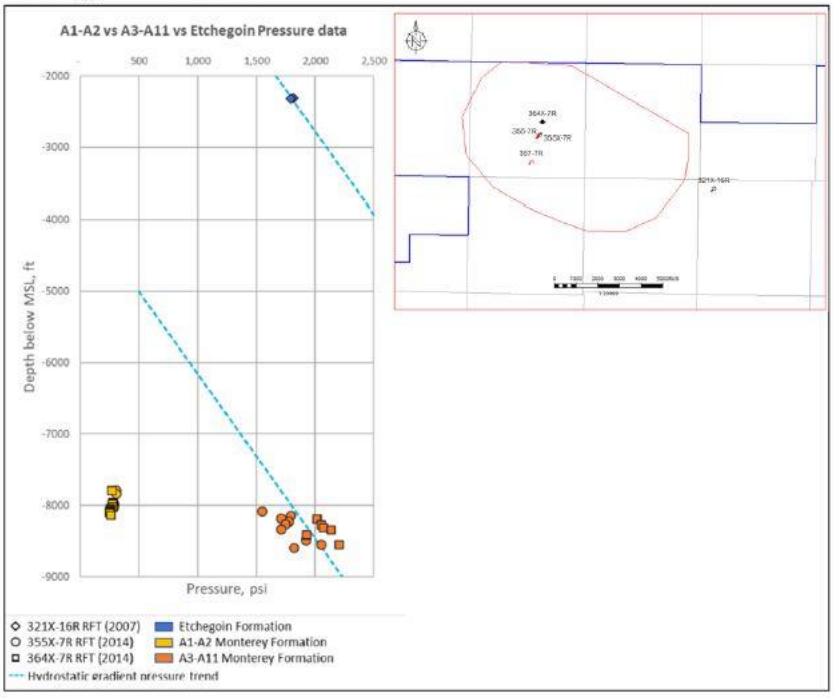
      CTV responded that the A1-A2 reservoir has high resolution data for stratigraphy and properties due to the quantity and quality of well data and the geological model is a well data driven model. CTV also states seismic was used to confirm structure and location of faults. CTV did not provide lithological modeled dip and strike cross sections previously requested. See requests below.
- Figure 4 in Attachment B states "The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale."
    - ***Please provide either a seismic section, well correlation panel, or both to support the statement made. Please show the pinchout and transitions to shale in both the dip and strike direction.***

      No new data was provided in the application material. CTV stated in the response that seismic is used to define the structure of the Monterey Formation and Reef Ridge Shale not stratigraphy. However, this is contradictory to the response to the question above. CTV states in answer above that the geologic model did not use seismic data. CTV did not provide lithological modeled dip and strike cross sections previously requested.
        - ***Please clarify how seismic data was incorporated into the geomodel.***
        - ***Please provide either a seismic section, well correlation panel to demonstrate the pinch-out and transitions to shale in both the dip and strike direction.***

- The Constitutive Relation section in Attachment B states "Material Balance is a well accepted method to determine the average saturations and fluid contacts in an oil and gas reservoir over time".
    - ***When was the last test or measurement that allowed for the determination of the gas-oil contact and oil-water contact at that time?***

      CTV explains in the response that production and injection data recorded from 1973 up till 2020 was used in the material balance as well as pressure data from 2014 – 2015.
        - ***Is the pressure data from 2014 – 2015 the most recent pressure data available?***
        - ***If there is more recent pressure data available, please provide analysis of the material balance with current pressure data and cumulative production and injection.***

Figure 11: Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated



- Figure 11 in Attachment B, shown above, presents pressure data from 2007-20014 in the AoR between different formations.
    - ***This data was obtained during production operations. Is there any data representative of the initial project conditions, when production has ceased, that can demonstrate pressure isolation?***

      CTV explained that the data between 2007-2014 is reflective of a period when there was limited production operations in the A1-A2 reservoir. However, pressure data of the Etchegoin at different time (such as in 2014 or after) is required to see if the pressure of the Etchegoin did not get affected by the reservoir production in A1-A2.
        - ***Please provide pressure data of the Etchegoin from 2014 or after to demonstrate the Etchegoin was not affected by reservoir production.***

Figure 112: Plan view showing the plume development through time for layer 15. Red dots ae the injectors, Blue dots are monitoring wells. Sections 8 and 17 have CO_2 in small quantities due to minor potential connected sand lenses, as the reservoir becomes shale dominated up-dip. It is highly unlikely that CO_2 will migrate to these areas.

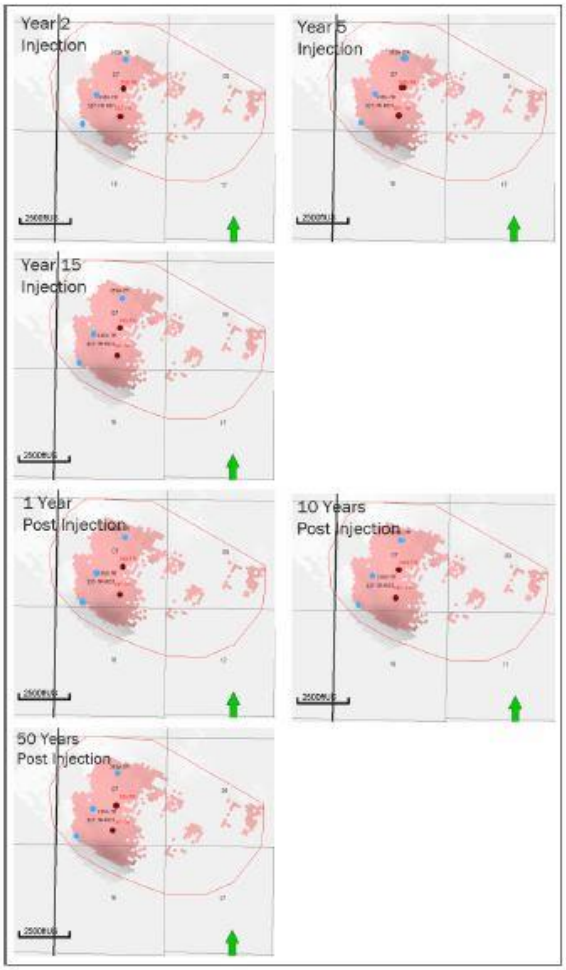
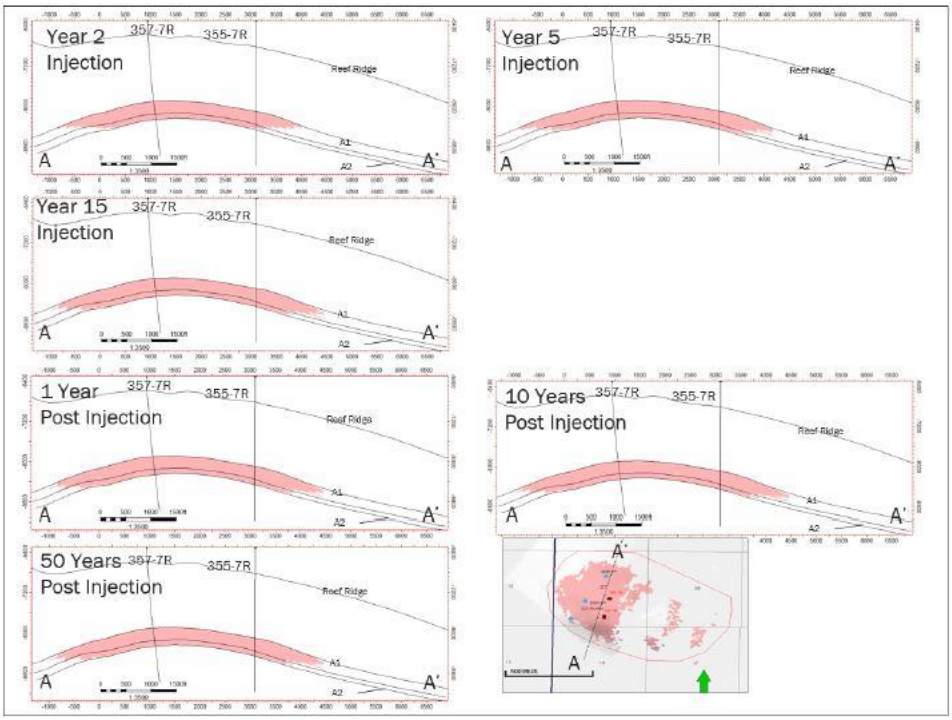


Figure 13: Cross-sections showing the plume development through varying times through the project.



- Figures 12 and 13 in Attachment B, shown above, illustrate plume development though various times of the project.
    - ***Please display the plume results to quantitatively show the saturation. Please include cross-sectional and plan view contour plots for both gas saturation and CO_2 saturation at various times in the project timeframe. Please include figures of the simulated pressure plume over time, both in plan and cross-sectional views.***
      CTV updated the figures, but additional details are necessary for the figures.
        - ***Please correct the typos in the caption.***
        - ***Please update the figure so the injectors are visible.***
- Figure 13 in Attachment B (above) depicts the CO_2 plume reaching the upper boundary of the model.
    - ***Please explain how the spatial extent of the model is sufficient if the CO_2 plume reaches the boundaries.***
      CTV states in the response that the CO_2 plume does not reach the lateral boundaries, but does reach the upper boundary and that since the upper boundary (Reef Ridge Formation) is a no-flow boundary the spatial extent is sufficient. However, the lateral extent size affects both the CO_2 plume and pressure front. Although CO_2 does not reach lateral boundaries, pressure may. The small model size may affect pressure change which could affect fluid dynamics within the model.
        - ***Please explain and provide justification for why the lateral extent size is large enough for the pressure front.***

- ***Please explain how no-flow boundary conditions are appropriate if the CO_2 plume reaches the boundaries.***
  CTV explains in the response that the upper vertical boundary of the model is the very low permeability Reef Ridge shale, which is the confining zone for the reservoir and although the CO_2 plume does not reach the lateral extents of the model, they are considered closed due to the production history of the reservoir which indicates a closed reservoir with no external pressure or aquifer extent. However, closed boundary conditions are about transport of fluid component across the boundary, not pressure. CTV should describe the pressure conditions due to injection at the lateral boundary.
  - ***Please describe the pressure conditions at the lateral boundary.***

- The Model Calibration and Validation section in Attachment B describes the different sensitivities that were run.
  - ***Please describe any uncertainty there might be with the interpretation and imaging of the structure bounding faults.***
    CTV explained how the 3D seismic survey was re-processed using enhanced computing and statistics, however, it is not clear if the data was incorporated into the geologic model to address any uncertainties in plume extent (preferential pathways) or fault-plume interactions.
    - ***Was the 3D seismic data incorporated into the geologic model to address any uncertainties in plume extent (preferential pathways) or fault-plume interactions?***
- The AoR Delineation section in Attachment B did not discuss whether there will be any concurrent operations in the area during the project timeframe.
  - ***Please include a description of known operations that will take place during the project timeframe and how that could affect the AoR delineation.***
    CTV stated in the response that all wells that are currently operating in the A1-A2 reservoir will cease operations and wells not associated with the project will be abandoned prior to injection. There are no further questions.
- The current x-y grid spacing around the injectors is too large to determine any near-field pressure effects.
  - ***Please analyze the reservoir with finer grid spacing around the injectors to illustrate near-field pressure buildup and determine that the maximum bottomhole pressure is accurately represented.***
    CTV states in the response that local grid refinement was run and analyzed but the results are missing in the application.
    - ***Please provide figures comparing the base-case to the results of the local grid refinement.***
- Attachment B does not describe how permeability anisotropy was incorporated.
  - ***Please discuss whether, or how permeability anisotropy was included in the model. Was any analysis done to determine differences between vertical and horizontal permeability?***
    CTV described in the response how permeability anisotropy was included in the model but did not provide the reference permeability used when the anisotropy was changed.

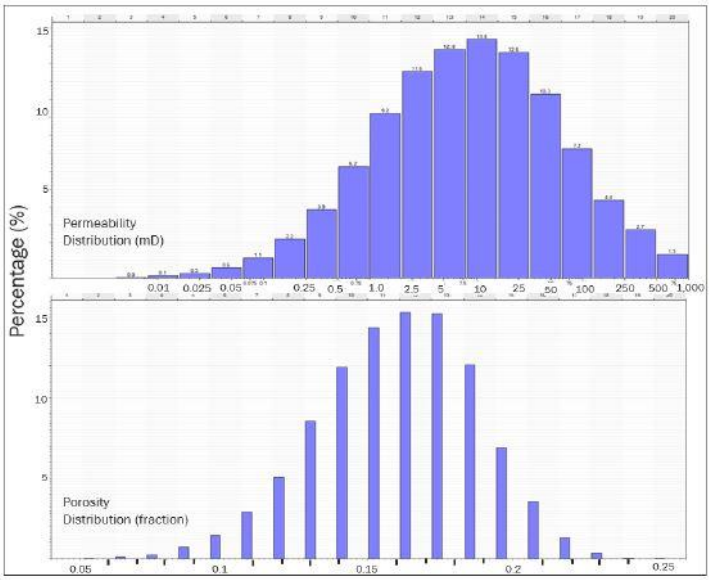
        - ***Please provide the reference permeability used when the anisotropy was changed.***
- Table 8 in Attachment B provides a summary of sensitivity cases. Case numbers 4 – 8 were run with increasing or decreasing the parameter by 10%. The 10% change appears to be arbitrary.
    - ***Please use a stochastic model to simulate sensitivities.***
      CTV updated the application with a stochastic analysis w using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. CTV should calculate the highest pressure with the sensitivity analysis in addition to storage capacity.
        - ***Please update the sensitivity analysis to calculate the highest pressure and AoR in addition to storage capacity.***

Incorporation of Site-Specific Conditions

This section of the review verified that the geologic description provided in Attachment A was accurately incorporated in the computational model. This included reviewing the incorporation of initial site conditions and operating information. The comments below include requests that are necessary to understand the incorporation of the initial site data and ensure consistency.

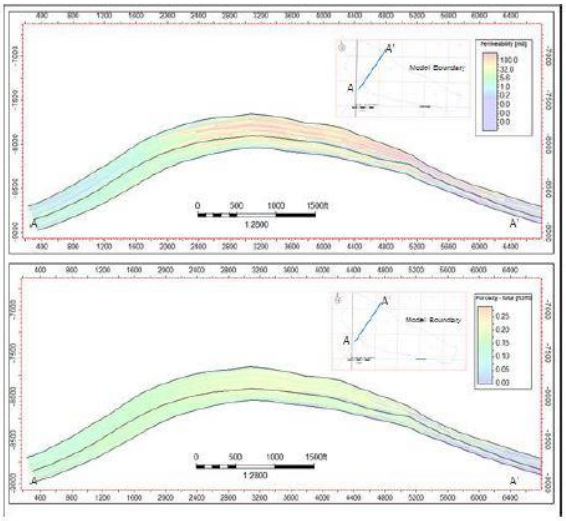
- Page 4 in Attachment B states "Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer." Recent profiles are important evidence for structural confinement.
    - ***Please provide recent pressure profiles and data.***
      CTV referred to Figure 13A, showing the vertical pressure profiles and states that pressure date will be gathered during the pre-operational testing phase. No further questions.
- Table 4 in Attachment B lists the initial reservoir temperature but there is no other information on how temperature was represented in the dynamic models.
    - ***Please explain how temperature was incorporated in the dynamic model initially and during injection.***
      CTV stated in the response that the base model was initialized using a uniform average temperature of 250 F to be conservative, based on temperature surveys conducted in 2014 – 2017. CTV also used GEM's Thermal option which indicated minimal effect on the system behavior. CTV needs to provide the thermal gradient used to evaluate if a uniform average temperature is conservative. Parameters used with the thermal option (e.g., thermal conductivity, specific heat capacity) are also needed to assess the applicant's model and analysis.
        - ***Please provide the thermal gradient used in the evaluation.***
        - ***Please provide the parameters used with GEM's Thermal option (e.g., thermal conductivity, specific heat capacity).***

Figure 7: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.



- Figure 7 in Attachment B shows porosity and permeability histograms for the Monterey Formation.
    - ***Please provide additional data (open-hole well log analysis) or other measured data that can be used to verify the permeability and porosity used in the static model.***
      No new data provided in application material. Attachment B would benefit from a map showing wells used in the model in addition to open-hole well log analysis as previously requested (well correlation windows showing raw vs. upscaled data, histograms showing raw vs. upscaled data, for example).
        - ***Please include a figure that shows the locations of wells that had data included in the model.***
        - ***Please include additional data (open-hole well log analysis) or other data (e.g. well correlation windows showing raw vs. upscaled data, histograms showing raw vs. upscaled data) to verify the permeability and porosity data used in the static model.***

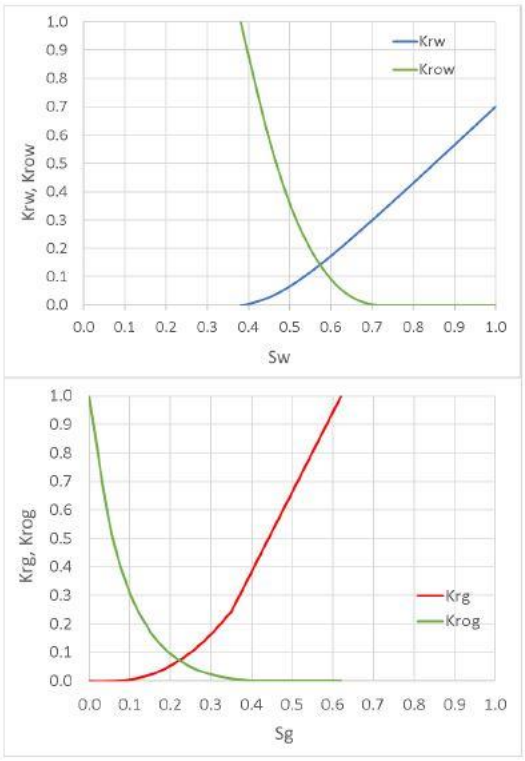
Figure 8: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



- Figure 8 in Attachment B shows the distribution of porosity and permeability of the reservoir at cross section A-A.
    - ***Additional visuals would help confirm the reservoir properties. Please provide a similar figure from a different cross section.***
      CTV provided an additional section to Figure 8 in attachment B. Figure 8 would greatly benefit from being higher resolution to see the AoR outline in basemaps.
        - ***Please provide a higher resolution version of Figure 8.***

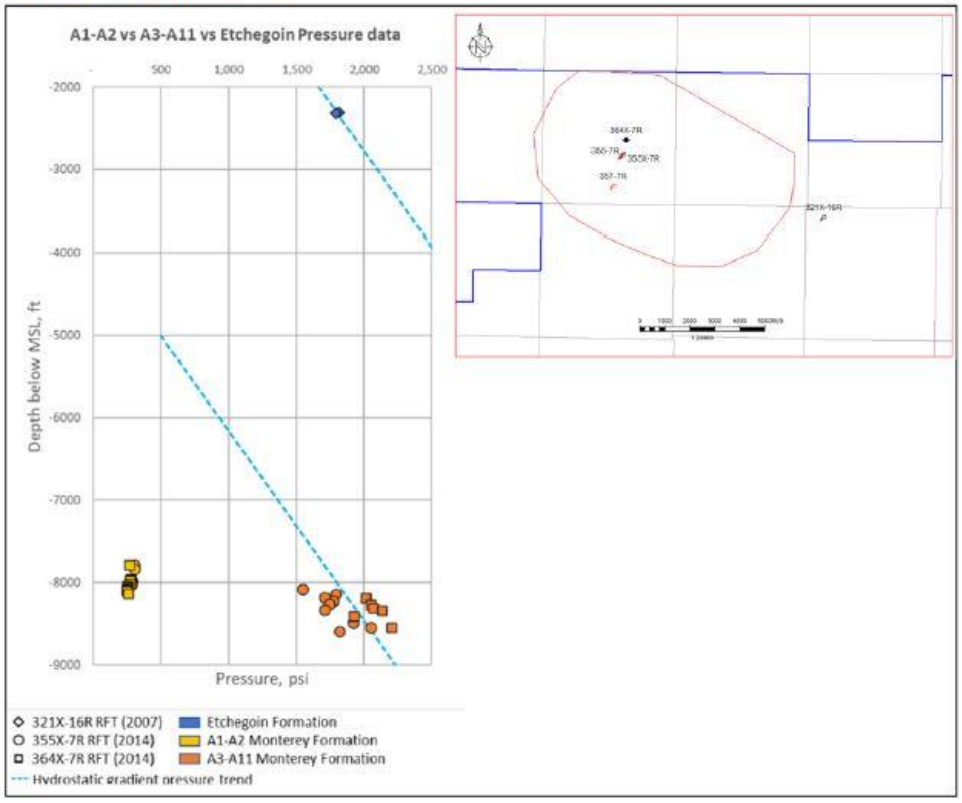
- The Maps and Cross Sections of the AoR section in Attachment A mentions a "comprehensive database", however there is not a reference to the database or any other information about it.
    - ***Please include a reference for the database described.***
      CTV stated in the response that the database is an internal database proprietary to CRC. No further questions.
    - ***Which wells submitted in Figure 5 Attachment A provide the information in the permit application? What are the sources of information?***
      CTV explained in the response that all the well information from the wells shown are used to define the regional surfaces. No further questions.

Figure 9: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study (krow = relative permeability oil in an oil-water system, krg = relative permeability to gas in a gas-oil system, krw = relative permeability to water in an oil-water system, and krog = relative permeability to oil in a gas-oil system).



- Figure 9 in Attachment B shows the relative permeability curves used in the computational modeling.
    - ***Please provide the functional forms that were used to create the curves shown.***
      CTV explained in the response the functional forms used to create Figure 9, however Figure 9 is not included in the updated version of Attachment B.
        - ***Please include Figure 9 in Attachment B, list the functions and their parameters in the narrative, and ensure that the plotted k-S-p relations are consistent with what was used in the model.***
    - ***Please include the data used to create the curves in a tabular form.***
      CTV states in the response Relative permeability data from wells 367-7R and 345A-36R are presented in tabular form in Figure 9 in Att-B, Pg 11, however Figure 9 is missing in the latest version of Attachment B, see comment above.

Figure 11: Formation pressure data in the area gathered in 2007 and 2014, after the blowdown of the A1-A2 reservoir, showing large pressure differentials between the A1-A2 and the underlying (A3-A11) and overlying (Ethcegoin) reservoirs, which supports the conclusion of the A1-A2 reservoir being pressure isolated



- Figure 11 in Attachment B pressure data from 2014 for the A1-A2 and A3-A11 reservoirs are shown.
    - Pressure measured at different times is needed to assure there is no migration. ***Is there any measured pressure data over different times? If so, please provide it.***
      CTV referred to Figure 14 in the response which includes pressure data for multiple wells. However, pressure data is needed for the same well at different times to see the impact of the production on the reservoir and confirm the isolation.
        - ***Please provide pressure data from the same well during production and after production to confirm isolation.***
    - Pressure in the Etchegoin Formation and A3-A11 reservoir is the same even though the y-axis shows their depth is very different. ***Please provide an explanation. If production from the A3-A11 reservoir resulted in pressure depletion, please include that in the explanation.***
      CTV stated in their response that the A3-A11 reservoir has been produced from since 1973. No further questions.
- The fracture pressure (0.82 psi/ft) is based on stimulation performed on well 327-7R-RD1. However, no information is provided for the confining zone. It is stated on page 30 of

Attachment A, “Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradient).”.

- ***Is there any data for the confining zone that supports the statement that the proposed injection pressure is lower than the confining zone fracture pressure? If so, please submit it.***
  CTV stated in the response that they will be completing pre-operational testing for the Reef Ridge. The fracture gradient is expected to be the same as or higher than the reservoir. No further questions.

- The Geomechanical modeling section in Attachment A, describes a generic two-dimensional model constructed to represent the reservoir.
  - ***How is the 2-D model with horizontal layering representative of the reservoir? Why was a 3-D model not used for the geomechanical evaluation?***
    CTV stated in the response that the 2D model is representative of stresses on the reservoir due to injection operations for the assessment of cap rock integrity, and to model sensitivities around the major factors affecting cap rock integrity - the thickness of the caprock, and the young's modulus but does not provide a justification as to why.
    - ***Is there pore pressure data derived from seismic with compressional sonic? If so, please incorporate the data.***
    - ***Are both injection wells included in the same geomechanical model simulation?***

- Figure 35 in Attachment A shows the fluid composition for the A1-A2 reservoir, however detailed information on the fluid model for the dynamic model was not provided.
  - ***Please provide fluid composition (i.e., mole fraction of each component considered) and relevant model parameters (e.g., binary interaction coefficients for each pair for Peng-Robinson Equation of State (EoS) or adopted EoS, viscosity model and its coefficients).***
    CTV stated in the response that a ten-component fluid composition was used for the simulation model with the composition shown in table 5. No further questions.
  - ***Please provide fluid model information based on results of the lab experiment (e.g., PVT experiment) analyzing up to date fluid sample from the site.***
    CTV stated in the response that limited PVT experiment data for the oil phase is available for original conditions of the reservoir but it is not representative of the current conditions of the reservoir. No further questions.