Comments on CTV II Computational Modeling
Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY22-4.1-4.5

This Computational and Static Modeling Evaluation report for the proposed Carbon TerraVault II (CTV) Class VI geologic sequestration project summarizes EPA's review of the computational modeling performed by CTV as described in the Narrative Report (Attachment A, Version 3.1) and the Area of Review and Corrective Action Plan (AoR CAP) (Attachment B, Version 3.2). Clarifying questions or requests that require further work are provided below in ***bold, italic*** text. Text that is not ***bold, italic*** is provided to give background information or is recommended for further work.

Summary of Significant Comments

1. Real evidence that the Stockton Arch Fault (SAF) is sealing / Boundary conditions / Size of the Model: The applicant states that the SAF is impermeable but provides little to no evidence to support that statement. This may significantly impact the spatial distribution of the CO_2 plume. ***Please provide strong evidence about the impermeability of the fault that would justify its consideration as a no-flow boundary. Alternatively, expansion of the eastern boundary of the modeled domain beyond the fault, and implementation of appropriate properties for the fault zone, could be used to show that the SAF is an appropriate no-flow boundary.***
2. Nature and Impact of the Flow Barrier: The applicant refers to an existing flow barrier identified at discovery, modeled as a no-flow boundary, that separates the northern and southern portions of the field. The cause or nature of the flow barrier was not discussed or shown in the Narrative. Additionally, there is no discussion on the way this flow barrier was modeled. Appendix 10: Critical Pressure Calculation shows simulated pressures across the whole plan-view extent of the model domain, and a sharp discontinuity in the pressure field, but no explanation for it. ***Please discuss the cause/nature of the flow barrier and how the flow barrier was modeled.***
3. Construction of Simulation Model / Vertical and Lateral Grid Discretization: The discussion of the construction of the simulation model is somewhat vague and qualitative. Additionally, there is little discussion on the upscaling process and how the grid resolution was chosen. ***Please provide a detailed discussion on the upscaling process and how the grid resolution was chosen.***
4. Uncertainty / Sensitivity Analysis: The sensitivity analysis conducted is very limited (i.e., uncertainty of ±10% was applied to porosity and permeability) and was only discussed qualitatively. These rather small perturbations would not be expected to have much effect on model results. ***Please conduct more thorough uncertainty analysis that includes:***
    a. ***Larger range of absolute permeability (e.g., this should be changed by an order of magnitude in each direction);***
    b. ***Relative permeability-capillary pressure-saturation function parameters (ideally also including hysteresis);***
    c. ***Boundary and/or fault properties (i.e., certainty that the boundary fault is sealing needs to be better demonstrated);***
    d. ***Impact of gas distribution and trapped gas in the initial conditions; and***
    e. ***A tornado chart showing relative importance of model variables to dynamic outcomes.***
5. Heterogeneities: ***Please provide more details about how the geological model was populated with heterogeneous parameters.*** The confining zone in the simulation model is extremely simplified, which was an unusual choice as the applicant has data to make a full resolution

model. ***Is the interface between the reservoir rock and confining zone treated as a no-flow boundary?***

6. Initial Pressure: ***The application needs more discussion of the potential (or lack thereof) for reservoir compaction due to the very low initial pressure of the gas field.*** Compaction would lower the amount of pore space available for CO_2 storage and could also negatively impact injectivity.
7. AoR Delineation / Determination of the Critical Pressure / Presentation of Simulation Results: Per EPA's guidance, the AoR is based on the results of computational modeling and encompasses the predicted maximum extent of the separate-phase plume or pressure front over the lifetime of the project. The material submitted has insufficient information regarding:
   a. The reasoning for the CO_2 plume delineation. The applicant defined the CO_2 plume front as the *0.1 CO_2 global mole fraction cutoff plus a buffer zone*. ***What is the rationale for using 0.1 CO_2 global mole fraction to delineate the AoR?*** It is not clear how this "cutoff" was determined. As a comparison, a former version of the AoR available seemed to have delineated the CO_2 plume with a 0.05 mole fraction. A mole fraction of CO_2 of 0.05 or 0.1 does not constitute a separate phase.
   b. ***Pressure at the wells and in the reservoir at times before plume stabilization*.**
   c. The determination of the critical pressure provided in Appendix 10. There is a clear pressure boundary between the north and south of the field, but no explanation has been given (see comment on section Nature and Impact of the Flow Barrier).
   d. ***More simulation results*.** In general, more results (even intermediate results) shown would be helpful in interpreting how sensitive the results presented in the application are to model choices. Additional plots to visualize the extent of the CO_2 plume would be needed. Cross-section plots through the line of injection wells would be useful to have in addition to a cross section or two parallel to the one currently shown, through locations where the plan-view plume plots show larger CO_2 mole fractions reaching the fault. Plots with CO_2 saturation would be needed as well (currently not shown or qualitative).
8. Geomechanical Modeling and Leakage Risk Assessment: ***Geomechanical modeling is needed because of the presence of the fault. Leakage risk assessment for fault and penetrating wells is also needed.***

Model Suitability

9. The software used by the applicant (Schlumberger Petrel for the static geological model, Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM) for fluid flow simulations, and PHREEQ-C for geochemistry) are suitable for the injection of impure CO_2 in the two scenarios the applicant studies.
10. Equations of state for CO_2 phase transitions can be used in CMG/GEM. The application mentions the use of Peng-Robinson Equation of State (PR-EOS) for interaction/solubility of CO_2 and residual gas in the reservoir, as well as Henry's Law applied to solubility of CO_2 in the aqueous phase (Attachment B, p. 2).
11. CMG/GEM was used with PR-EOS and Henry's law, which is appropriate for the injection of the two CO_2 streams shown in table 7.2 of the Narrative (Attachment A, p.68). CMG/GEM accounts for salinity effects (on fluid density and viscosity), diffusion, dispersion, non-isothermal conditions, etc. There is no discussion about whether heat transport or residual phase trapping were considered in the model simulations, the equations were not provided. ***Please provide***

equations for how heat transport and residual phase trapping are considered in model simulations in Attachment B.

12. Geochemical reactions were not modeled, but separate geochemical reaction modeling was apparently performed using PHREEQ-C (Reported in Appendix 3: CTV II geochemical modeling). The applicant reports that the PHREEQ-C results suggest that the effects of geochemical reactions are minimal over the 100-yr post injection simulation timeframe, which was used to justify not simulating geochemical reactions with GEM ("*Based on the geochemical equilibrium modeling, the injection of carbon dioxide at the CTV II site does not cause significant reactions that will affect the injection or containment of the gas.*").
13. The model can accommodate site-specific geologic conditions and operational scenarios involving variable injection schedules and wells with multiple perforations. However, it is acknowledged that in a thrust setting, it is difficult to capture both the footwall and the hanging wall, but the static model has not taken sand-sand juxtapositions with the hanging wall into account. ***What is the proof for fault sealing? It is stated that the field boundary fault is a proven seal, but this has not been demonstrated in the Narrative. For more information see the Appendix of this document for comprehensive explanation of the implication. Additional questions about the SAF sealing properties:***
    - ***a. Is it a simple juxtaposition seal against shale? If there's a sand-sand juxtaposition across the fault: is the original gas-water contact deeper than the structural spill point?***
    - ***b.*** "*Wells were reviewed that drilled on both sides of the fault*." However, Figure 2.1-7 for Attachment A seems to suggest that there are only penetrations in the footwall. ***Has the area to the east of the SAF been penetrated by wells? Some maps show no wells in that area, others only one. Is there a valid structural test of the Lathrop Sand in the hanging wall? The fact that off-structure penetrations of the Winters Sand in the hanging wall were water-bearing does not mean that the fault is sealing.***
    - ***c.*** P.22 of Attachment A, the applicant states that the "*The Stockton Arch Fault has a sealing capacity adequate to trap natural gas for millions of years, it will also provide a seal to trap injected CO_2.*" ***Please provide information from the previously drilled wells about the presence or absence of hydrocarbons in the hanging wall.***
14. Description of the original fill of the field needs more explanation using maps and cross-sections:
    - ***a. Please provide a cross-section with the original fluid contacts, spill point and fault juxtaposition to demonstrate the sealing nature of the fault and the trapping mechanisms. (See Appendix of this document.)***
    - ***b. Show original gas-water contact (OGWC) to explain how the trap works, especially because the top reservoir map does not close.***
    - ***c. Explain why some figures show an antithetic fault to the SAF, but others do not. An antithetic fault will change the juxtaposition against the hanging wall, which is important for the explanation of the fault seal.***
    - ***d. Provide an Allan diagram of the SAF indicating fluid contact and spill point level.***
    - ***e. Winters facies change: Why has the shale-out line not been used as a 0-thickness line in the isochore gridding?***
    - ***f. Explain why the AoR does not follow the gas field outline.***
    - ***g. Does the CO_2 plume extend below the OGWCs?***
15. ***What causes the N-S divide or flow barrier within the field: A fault or a facies change? Is there a sealing fault there that is not known or described? Identify the flow barrier mentioned in the text in Figure 3.3 of Attachment B and explain the causes of the boundary.*** In section 3.1.2 of Attachment B, the applicant states that "Different gas water-contacts observed at the time of

the field's discovery indicate a flow barrier exists within the Injection zone, between the northern and southern halves of the field." ***Can the flow barrier be seen in seismic profiles?***

16. ***Lithology older than the Delta Shale needs to be described.*** It appears that fault juxtaposition with the Lathrop Sand is important.
17. ***The statement of different gas-water contacts (GWCs) at discovery in Attachment B documents needs to be made in the Narrative as well.*** This is important information that requires an explanation and demonstration with (seismic) cross-sections and correlation panels.
18. In Attachment B, p.6, the applicant defines the northern boundary as being closed because of limited evidence of aquifer influx during historic gas production. It seems like the impacts of this important assumption were not tested. ***Were other locations for the northern boundary considered? (See also sensitivity analysis section of this document.)***
19. The discussion of the construction of the detailed geological and simulation model from the structural model is very limited. There is a detailed discussion of creating the structural model (Attachment A, section 2.2), but the discussion of creating a simulation model from this data is largely qualitative (Attachment B, p.5). This is illustrated by the following statement, "*This was then upscaled to 200 feet x 200 feet for the dynamic modeling. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement."* ***Please describe the gridding around the injection wells and the upscaling process.***
20. ***Please provide seismic lines and well correlation panels to explain the following features:***
    a. ***Regional geological setting;***
    b. ***Original fluid fill, (both North and South parts of the field) including structural spill point;***
    c. ***Fault juxtaposition across the SAF;***
    d. ***Reservoir shale out; and***
    e. ***N-S divide of the field.***
21. ***Figure 3.2 of Attachment B is an important figure showing a reservoir facies change. Please include this figure in the Narrative as well. Can the shale-out be seen on seismic? Are there wells that penetrate the Winters formation in both the hanging wall and footwall? If so, please show the hanging wall penetrations.***
22. ***Figure 3.4 of Attachment B: Please provide a strike section that shows the flow boundary separating the North and South of the field.***
23. ***Figure 3.6 of Attachment B: Please display the reservoir shale-out line in the figure.***
24. ***Figure 3.16 of Attachment B: Will any new wells be drilled for monitoring (e.g., in the north)?***
25. ***In Attachment A, section 2.2.1, why is the Lathrop formation not listed?*** It appears that Winters-Lathrop sand-sand juxtaposition is occurring across the SAF (see Appendix of this document).
26. ***In Figure 2.2-5 of Attachment A, the fault boundary is clear but what determines the boundary downdip?*** It appears that the top reservoir map doesn't close. Please show the original fluid contact(s) to demonstrate how the trap works. ***Why has the shale-out line not been used as a 0-thickness line in the isochore gridding?***
27. About the wells completion/operating conditions:
    a. On the schematics listed in Appendix 5 of Attachment A, it appears the applicant is using open perforations extending the entire thickness of the Winters Formation while the perforated intervals for each injector are listed in Table 3.5 of Attachment B. ***Please clarify how well completion was implemented into the simulations.***
    b. ***Please confirm if the wells are constant-rate injectors subject to a maximum injection pressure.***

Model Design

28. The model extents appear to go beyond the anticipated plume front, defined by a CO_2 mole fraction of 0.1 (Attachment B p.18, "The boundaries of the AoR have been defined with a 0.1 CO_2 global mole fraction cutoff plus a buffer zone."). However, it is not clear whether the AoR extends beyond the structure spill point, and how the eventual plume relates to structural spill. ***Please explore and provide information on the impact of the northern boundary location, as mentioned in Comment 18 above.*** The risk of leakage into the hanging wall has not been addressed. The applicant has considered that the SAF is a fully impermeable boundary, such that the eastern part of the model domain is limited to that area. Very limited evidence was shown to back up this assumption, although this may highly impact the extent of the pressure and CO_2 plume. As it is, the plume stops at the fault because it is defined as a boundary and not necessarily because the properties of the fault do not permit the plume to advance. If the fault is not totally impermeable, the plume could potentially extend beyond the fault.
29. ***In the Appendices (CTV II AoR _CA AoR Delineation.pdf), the plume front is defined by a CO_2 mole fraction of 0.05. While the appendix seems outdated and corresponds to a former version of the model including two injectors, how and why was such a decision/change made?***
30. Grid spacing is discussed briefly in the application. "*The geo-cellular grid was initially built with uniformly spaced 100 feet x 100 feet cells throughout the 36.9 square mile model area […]. This was then upscaled to 200 feet x 200 feet for the dynamic modeling. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement*." (Attachment B, p.6). While the grid may be fine enough to resolve local heterogeneities, it is not clear how this was determined, other than to say that finer resolution would prevent the simulation from running efficiently. ***Was a grid sensitivity test performed? What metrics did the applicant use to decide this grid was "adequate resolution for plume development"?***
31. The applicant discusses the vertical upscaling process and indicates that the 5-ft cell height is sufficient to capture lithologic heterogeneity (Attachment B, p.7). However, some upscaling was performed such that the average cell height is 9 ft. ***Please explain distribution of cell heights.***
32. The images showing the heterogeneity are very small (e.g., Fig 3.9 of Attachment B) and there is no discussion of how the uncertainty of properties were propagated through the model. The mean porosity and permeability values of each facies are in the Narrative, but the applicant doesn't state the correlation lengths used parallel and perpendicular to the depositional trend of the injection interval (see first paragraph p.6 of Attachment B). ***Please provide a table in the document with all this information for all the formations included in the dynamic simulation model.***
33. CMG/GEM can address preferential pathways for fluid movement. ***Please explain why no preferential pathways for fluid movement were incorporated into the dynamic fluid flow model.***
34. ***Please provide plots or tables of the time-history of well pressures from discovery to present day.***
35. Pressure front behavior over time was not reported or shown. Instead, the AoR was delineated by the simulated CO_2 plume front defined by a CO_2 mole fraction of 0.1 (or 0.05 in a previous version of the AoR delineation using two injectors depending on the document reviewed, see Comments 7 and 29 above). ***Model results should include an estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the***

injection zone over time. The evolution of CO_2 concentration over time is shown in Figure 3.13A and Figure 3.13B of Attachment B, but the scale (i.e., CO_2 concentration/saturation) is not displayed but is read as "CO_2 Concentration for 100-Year CO_2 plume".

36. Cross-section plots through the line of injection wells would be useful to have in addition to a cross section or two parallel to the one shown in Attachment B (Figure 3.14A), but through locations where the plan-view plume plots show larger CO_2 mole fractions reaching the fault. *Although these figures indicates that the plume growth over time is driven by the reservoir anticlinal structure, additional figures would be useful.* For example, the figures from the former and current versions of the AoR delineation document (i.e., 2 injectors vs 5 injectors). Without additional cross-sections, it seems like the CO_2 is only located in the Northern part of the field (i.e., anticlinal structure), while it is demonstrated in Figure 3.13.B that the CO_2 plume extends much further.
37. ***Please show the pressure throughout injection in plan-view and/or side view.*** Only pressure at plume stabilization after 100 years is discussed. It is recommended to show plots similar to Figures 3.13 and 3.14 of Attachment B for pressure as well as saturation. Pressure at the wells during injection is not shown other than the average/maximum values in Table 3.6 of Attachment B. ***This information needs to be included in more detail.***
38. ***Please clarify what time step values were used in the simulation.***
39. Model simulation results are shown for the commencement of injection activities to 100 years post-injection. The discussion on model simulation results indicates that the plume is largely stabilized by year 30. This appears to be true with respect to the western boundary, but some plume growth is observed between 50 and 100 years toward the eastern boundary (see Figure 3.13A of Attachment B). ***Please review the choices of boundary conditions for the delineation of the AoR and evaluation of plume stability.***

Input Parameters vs. Site-Specific Conditions

40. ***Why is there an omission of dissolved gas in the liquid phase between the current gas/water contact and the original gas/water contact?*** It could negatively impact the storage capacity as there would be less residual CO_2 trapping in the presence of a pre-existing trapped gas phase.
41. ***Please compare the relatively simplistic assumed initial condition with the simulated current state of the reservoir based on the known gas production since discovery in 1972.*** It is possible that, due to the low reservoir connectivity, pressure is not as low in the reservoir far from the wells as assumed in the initial condition.
42. As discussed in Comment 5 above, there is insufficient description of how heterogeneous permeability was populated in the model. ***Please provide maps of permeability and porosity at different angles than Figure 3.9 of Attachment B.***
43. The model utilizes a porosity-permeability correlation function that was developed from core data collected from wells located ~2 miles away from the planned injection site(s) (see Attachment B, p.13). *Despite the fact that the applicant plans to collect additional core data from the actual field as per the pre-operational testing plan, it is recommended that the applicant try to gather additional site-specific data during the pre-construction phase of the project.*
44. While a capillary pressure curve is provided, there is no detailed discussion of capillary pressure and relative permeability parameters. The applicant states that Corey relative permeability models (Fig 3.10 Attachment B) are used, but no parameters or equations are given, the capillary pressure model is plotted (Fig 3.11 Attachment B), but again no parameters or equations. ***Please provide a detailed discussion of these parameters and clarify whether a***

single set of parameters are used for the full model, or if they are based on facies or absolute permeability.

45. ***Please provide more information about the confining zone properties. It appears that the confining zone is assumed to be homogeneous, which seems unnecessarily simplistic, given the level of characterization data available for this field.*** The capillary entry pressure in the caprock is a very important parameter, however, it appears that the applicant considered this to be a no-flow boundary, since there is little to no information provided about it.
46. Formation initial conditions are summarized in Table 3.4 of Attachment B. ***Please clarify whether the model included a geothermal gradient***.
47. Coupled geomechanical modeling was not performed. ***While pressure is expected to remain lower than discovery conditions, analysis of potential for fault reactivation is needed, from a risk assessment perspective.***
48. No fracture gradient information is currently available for the Upper Confining Zone but the applicant plans to conduct a step rate test as per the pre-operational testing plan. A 0.7 psi/foot fracture gradient is assumed for the injection zone at present. ***Please provide a rationale for this assumption.*** Step-rate testing will also be conducted as part of pre-operational testing plan in the injection zone. The simulated injection pressures are predicted to remain far below the estimated fracture pressure (which still needs to be measured).
49. As stated in Comment 2 above, there is ambiguity or a lack of information on the model setup related to an apparent "flow barrier" between the northern and southern parts of the model. Specifically, in p. 6 of Attachment B, the applicant states that "The flow barrier identified at discovery is modeled as a no-flow boundary and partially separates the northern and southern portions of the model." There is no other discussion or explanation about this feature. Fig 2 in Appendix 10 Critical Pressure Calculation shows simulated pressures across the whole plan-view extent of the model domain, and a sharp discontinuity in the pressure field, but no explanation for it (is it a mistake and were the wrong simulation files (i.e., two injectors) represented?). The model is also bounded to the South-East by the SAF, which is treated as a no-flow boundary. ***How do we know this fault boundary is impermeable?*** No evidence or discussion about this is provided. It is mentioned that there is a boundary between the North and the South of the field, but the cause of the boundary (fault, reservoir) has not been explained.
50. ***Please show the injection well locations in Figure 2 of Appendix 10.***
51. The SAF is assumed to have no transport, however, there is not enough evidence to make this assumption. The buoyant force of CO_2 is different from brine, and it can leak without sensible pressure perturbation. ***Please provide equations for how mass transport is considered in model simulations in Attachment B.***
52. ***In the Narrative, it is stated that the "CTV forecasts the potential CO_2 stored in the Winters Formation at 0.97 million tonnes annually for 23 years.", but operating details provided in Table 3.5 of Attachment B seem to show that the injection duration is 24 years. Is this just a mistake or does this have consequences on the numbers provided?***

Description of Computational Modeling Results

53. ***Model results should include an estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone over time because the boundaries of the AoR are based on simulated predictions of the maximum extent of the separate-phase CO_2 (i.e., supercritical, liquid, or gaseous) plume and pressure front over the lifetime of the project.*** The evolution of CO_2 concentration over time is shown in Figure 3.13A and Figure 3.13B of Attachment B, but the scale (i.e., CO_2 concentration/saturation) is not

displayed and is read as "CO_2 Concentration for 100-Year CO_2 plume". ***Please include a scale to these figures.***

54. ***Regarding the reservoir pressure, section 3.2.2 of Attachment B indicates that "For both injectate scenarios, CO_2 was injected into the depleted Injection zone until the reservoir pressure reached 90% of the discovery pressure of 5,040 PSI.", which leads to 0.9*5,040 = 4,536 psi. However, Table 3.6 of Attachment B refers to maximum injection pressure that could not exceed 90% of the fracture pressure (e.g., 0.9*0.7*6,714 = 6,043 psi for SONOL SECURITIES 1-A injector). Shouldn't these values be consistent?*** The applicant has chosen the right approach in considering the 90% fracture pressure to determine the maximum injection pressure. However, this pressure may locally exceed the discovery pressure while the applicant states the "Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection." (Attachment B, p.2).
55. Regarding the determination of the critical pressure, the applicant is using the equation proposed in the EPA AoR and Corrective Action Guidance. *However, units/parameters are not consistent with the equation provided in the guidance (SI vs imperial units, depth vs elevation), and it would be recommended to use such a visual and/or clearly list the parameters and associated units considered to make the review process easier and conceptually represent the system.* ***Please see the example in Box 3-2 beginning on p.43 of the EPA AoR and Corrective Action Guidance***.
56. The modeling results only reflect the extent of CO_2 plume. Very limited pressure front results prior to stabilization are presented. The pressure is only presented in tabular form for the wells (max, average) and after plume stabilization for the full-field model.
57. No plots or tables are shown that directly indicate that the simulation results are consistent with the planned injection amounts.
58. The pressure front modeling results that are presented are very limited. The AoR was not defined by the pressure front, but rather by the CO_2 mole fraction of 0.05. Some of the plots that show the simulated CO_2 mole fractions have legends that are not labeled, so it's not always clear from the presented results what is being displayed.

Model Calibration and Sensitivity Analyses

59. Porosity, permeability, and injectate type were varied. The results were not sensitive to these varied parameters according to the application. The sensitivity analysis conducted is limited and the result isn't described quantitatively as in Table 3.7 of Attachment B. It is difficult to know which parameter is the most impactful.
60. ***An uncertainty of ±10% was applied to porosity and permeability. Two injectate compositions were tested. A greater range of uncertainty is needed. A larger range of absolute permeabilities should be considered. This should be changed by an order of magnitude in each direction, not 10%.*** The parameter values chosen seem reasonable, but results are not shown for cases where uncertainty is included, so it is not possible to determine how much the AoR would extend (with the SAF as a boundary, the AoR is not permitted by the model to extend to the East). Larger perturbations to the porosity and permeability values could extend the AoR beyond what is presented.
61. The relative permeability and capillary pressure data were collected from two wells (Fig. 3.2 of Attachment B) that do not represent the entire site. The poro-perm correlation function used in modeling was based on core data obtained from wells located more than 2 miles away from the proposed injection site. The applicant should collect additional permeability, relative

permeability, and capillary pressure-saturation curves when the wells are drilled and tested. ***Please determine the model sensitivity to relative permeability and capillary pressure-saturation relations/function parameters. Both are based on limited core data from single wells in the field. This is particularly important as the relative permeability model used is quite simple and does not appear to include hysteresis.***

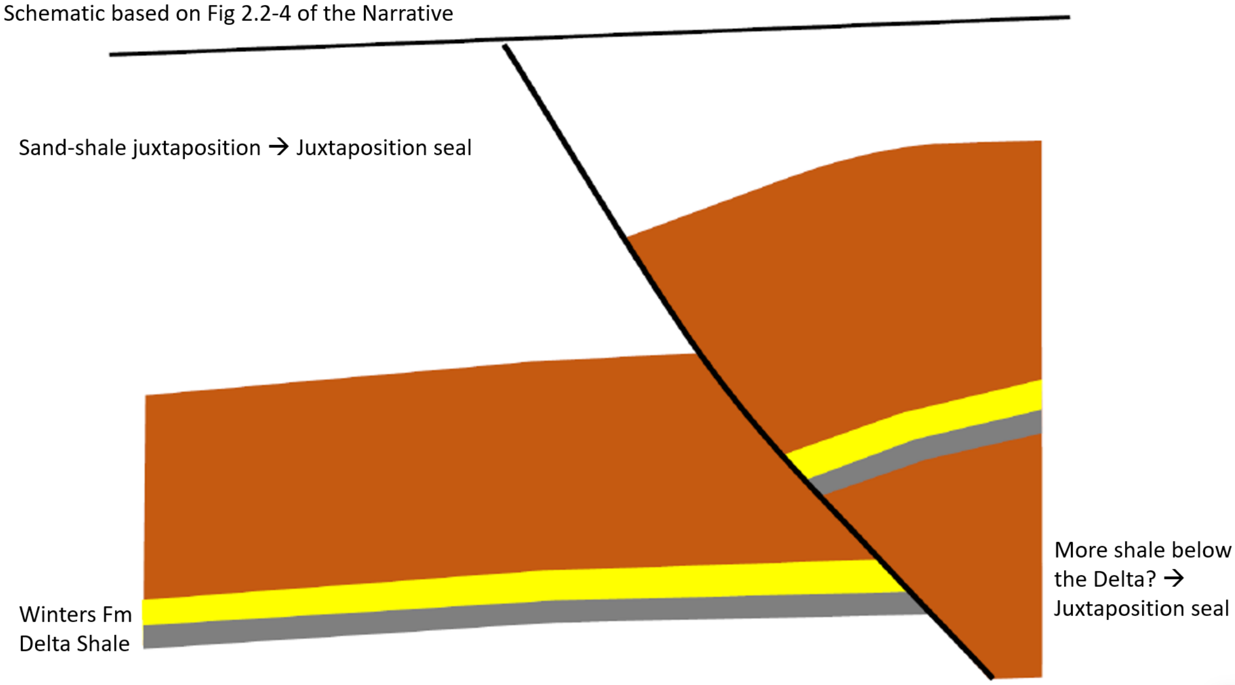
62. ***Simulations with trapped gas below the present gas/water contact should be conducted, as the lower CO_2 trapping in the presence of residual gas may increase the size of the plume.***
63. ***The applicant mentions in the section 3.2.2 of Attachment B that the model was validated by comparing the area of the reservoir that has been depleted by gas production and initial gas contacts with the modelling results. Please show results from this comparison.***
64. A qualitative discussion of the impact of vertical refinement was presented, but no discussion of the impact of horizontal mesh refinement was presented. ***This should be explained in more detail, as discussed in Comment 30.*** The static model was built using 100 x 100 ft (X-Y) grid with constant 5-ft vertical resolution. The grid was upscaled to 200 x 200 ft (X-Y) and variable (9-ft-average) vertical resolution for the dynamic model. The application says that a coarser mesh would not adequately simulate plume movement, but results are not shown.

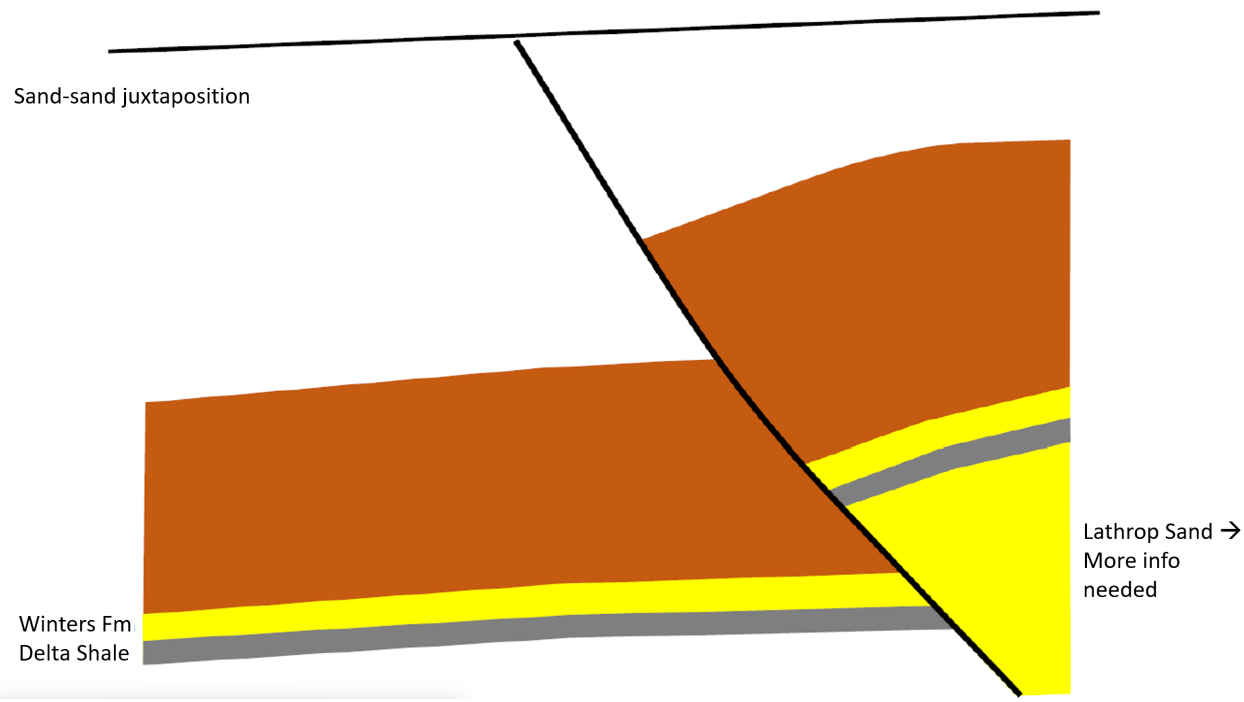
General Comments

65. The application needs more discussion of the potential (or lack thereof) for reservoir compaction due to the very low initial pressure of the gas field. Compaction would lower the amount of pore space available for CO_2 storage and could also negatively impact injectivity.
66. In general, more results (even intermediate results) shown would be helpful in interpreting how sensitive the results presented in the application are to model choices.
67. Mismatch between Narrative and critical pressure calculation. The latter shows a clear discontinuity in pressures between the north and south parts of the field, but no explanation has been given.
68. Geomechanical modeling is needed especially for the fault, leakage risk assessment for fault and penetrating wells.
69. Pressure build-up is not negligible (Appendix 10), and the pressure front plume is not considered enough for risk assessment. The leakage of not only CO_2, but also formation brine is also a risk.
70. Additional analysis of the closed northern boundary assumption is needed.
71. Quantitative discussion of upscaling to 200x200 m simulation grid is recommended.
72. Plots and discussion of pressure at the wells as a function of time and pressure distribution throughout the reservoir at various snapshots in time (e.g., use the same times as the plume snapshots: 1, 5 10, 15, 23, 30 and 50 years) are needed.
73. Additional uncertainty simulations with a larger range of absolute permeability are needed.
74. Simulations including trapped gas below the present water/gas contact are needed.
75. A grid sensitivity study would be helpful.
76. Applicant should either provide more evidence about the impermeability of the SAF or expand the domain to the East beyond the SAF to show the potential extent of the plume in later years.

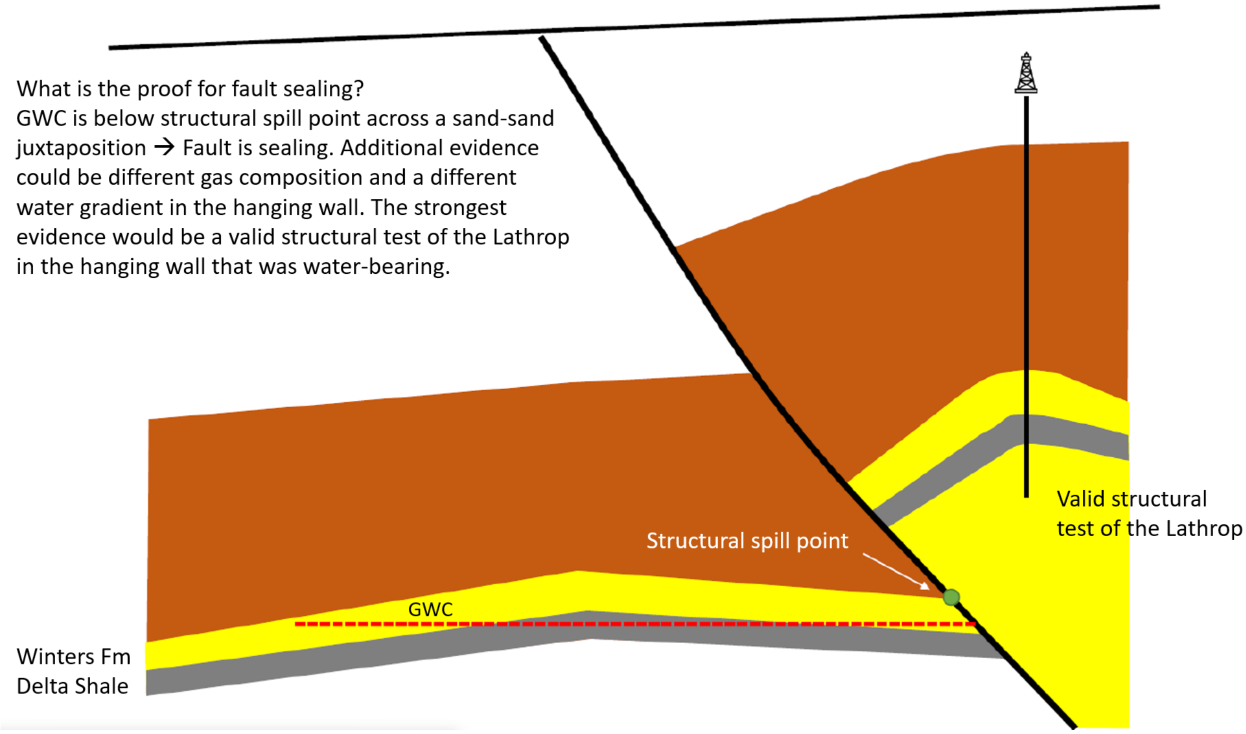
Appendix

Schematic based on Fig 2.2-4 of the Narrative





What is the proof for fault sealing?
GWC is below structural spill point across a sand-sand juxtaposition → Fault is sealing. Additional evidence could be different gas composition and a different water gradient in the hanging wall. The strongest evidence would be a valid structural test of the Lathrop in the hanging wall that was water-bearing.



What is the proof for fault sealing?
GWC is controlled by a structural spill point on the fault → Fault is leaking, unless a valid structural test of the Lathrop in the hanging wall, that is on the fill-spill chain, was water-bearing.