Evaluation of Applicant's Responses to EPA's Comments on CTV II Computational Modeling
Class VI Pre-Construction Permit Application No. R9UIC-CA6-FY22-4.1-4.5

In December 2024, CTV responded to EPA's August 2024 request for additional information about computational modeling in the CTV II Class VI permit application. EPA's evaluation of the applicant's responses is provided in red text in the "Reviewers' Evaluation of Company's Responses" column of the table below. Comments provided below in ***red, bold, italic*** text require additional information, clarification, and/or further work from the applicant.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
1	Summary of Significant Comments	***A new section related to the discussion about the sealing properties of the fault was added (Section 2.3.2).*** ***The primary evidence focuses on initial pressure conditions and drawdown conditions which are not being contested. However, reliance on secondary pressure evidence from mudlogs - described as a second evidence - presents challenges, particularly in a mature field. The final and most convincing evidence described by the applicant points to similarities in discovery pressure gradient between Union Island (0.519 psi/ft) and Lathrop gas (0.512 psi/ft) despite 10 years difference in discovery date.*** ***The modeling and understanding fault seal/stability are a highly uncertain process; It is recommended to focus on mitigation (e.g., additional***	See responses. Attachment A Section 2.2.1 Section 2.3.2	*New eastern fault block monitoring well M-2 will be installed prior to injection and will primarily be used to monitor leakage across the Stockton Arch Fault and is not expected to encounter CO_2. Measurements on this well will be limited to pressure and temperature at the initiation of the project. Should these measurements indicate signs of leakage, further diagnosis and fluid sampling will be initiated. This text has been added to Attachment C, Section 9.3.* *Attachment A, Section 2.3.2 has been updated to add additional information on fault sealing. Below are responses to address the specific comments in the "Reviewers' Evaluation of Company's Responses" column.* • *The Allan Diagram was updated to account for the Lower Delta Shale. As seen in **Figure A-25**, the Winters Injection Zone on the footwall side of the fault is mainly juxtaposed against the Lathrop Sands on the hanging wall, with only a portion juxtaposed against the Lower Delta Shale in the southern portion of the AoR. The discrepancy between the prior Allan Diagram showing Winters-Sacramento Shale was due to a zonal labeling error*	The reviewers concur with the applicant's response with the caveat that updates to modeling will advance with data collected from the planned pre-operational testing. The reviewers note that an injection test of sufficient duration can help answer questions about the sealing efficiency of the Stockton Arch Fault (SAF) if results of the test do not conform to infinite boundary assumptions. The reviewers realize that this may or may not be practical depending on conditions during the injection testing. ***The statement, "Measurements on this well will be limited to pressure and temperature*** **at the initiation of** ***the project" is ambiguous and needs to be clarified. Why just at the initiation of the project? Does this mean once, in the first few hours or days after injection starts? What if leakage occurs later? EPA requests that the applicant propose/establish a regular, longer- term monitoring schedule for well M-2 and clarify the sentence in question modified accordingly.*** Allen diagram and related updates (Text and Figs A-25 to A-30) are much improved. Previous related comments/questions have been addressed.

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		monitoring wells, operational limitations/phase in). ***A methodology to show initial pressure gradient, GWC, Allan diagram, and Shale Gouge Ratio (SGR)*** ***determinations would bolster evidence that the fault is sealing:*** ***Allan Diagram results (show mostly winters-*** ***Sacramento shale) are not consistent with text (states sand on sand).*** ***3D seismic cross sections are not provided.*** ***Figure A-20 should show Winters-Lathrop juxtaposition; facies model display (and stratigraphy consistent with Figure A-22).*** ***- Expansion across eastern boundary was not included.*** ***How was fault seal calculated without modeled*** ***properties?*** ***Gas-Water Contact: structural spill should be based on threshold pressure as well as structure (no*** ***methodology provided). It is unclear if the AoR*** ***surpasses original fill point. It is***		*where the Delta Shale Base (DELTA_SHALE_# in **Figure A-27** as an example) was not also the top of the Lower Delta Shale. This has been fixed and the Lower Delta Shale added to **Figure A-14** for clarity. The updating zoning now shows the correct sand on sand juxtaposition in **Figure A-25** and creates updated SGR values shown in the text (Attachment A, Section 2.3.2) and this response* • *As discussed in Attachment A, Section 2.2.1, well data are used in conjunction with three-dimensional (3D) and two- dimensional (2D) seismic data (**Figure A-12**) to define the structure and stratigraphy of the Project area within the bounds of the structural model (**Figure A-13**). This includes the Stockton Arch Fault and the Eastern Fault Block (EFB). The Stockton Arch fault Allan diagram was generated from this data and is shown in **Figure A-25**.* • *As requested, the Winters-Lathrop juxtaposition has been added to **Figure A-22** (former Figure A-20). This figure displays the geologic surfaces (horizons) and faults developed from the 2D and 3D seismic interpretation which were generated to create a*	

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		recommended to add GW contact to base map in Figure A-23. ***SGR: The methodology is not described. It is recommended to add inputs (VClay/Facies) to Figure A-24. A justification and/or reference is needed for 15% SGR sealing cutoff (usually in the range of 18-25%). No figure is presented to show the results of SGR.*** ***Hanging wall well penetrations are shown in Figure A-24. However, the reviewers would like to see facies log/3D cross section across facies model (more precise placement of Stockton Arch Fault).*** ***---*** ***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***		*velocity model for mapping and gridding purposes (see Attachment A, Section 2.2.1). It is these depth horizons that are the basis of a framework that uses conformance relationships to create a series of depth grids that are controlled by formation well tops picked on well logs. It is these depth grids that are used define the stratigraphy displayed in **Figure A-14**, **A-15**, **A-16**, **A-25**, **A- 26**, **A-28**, **A-30**, **A-38**, and **B-1**.* • *Gas water contacts were determined from logs combined with production results. The gas water contact has been added to the Allan Diagram (**Figure A-25**). Refer to **Figure B- 23** for map view of the gas water contact in comparison of the Area of Review (AoR).* • *Attachment A, Section 2.3.2 has been updated to discuss the Shale Gouge Ratio (SGR) methodology and calculations. As stated in the text, SGR is a fault seal algorithm used to estimate the sealing potential of a fault-zone (Yielding et al, 2010). The SGR calculation takes stratigraphic thickness, throw, and clay volume into consideration using the following equation:* $SGR = \frac{\Sigma(Vcl \times \Delta z)}{throw} \times 100\%$ *(Eq-1)*	

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		the SAF is an appropriate no-flow boundary.		*where Vcl is the clay volume content, Δ is the stratigraphic layer thickness, and throw is the offset of the layer of interest. The Vcl values were calculated from well logs from 11 different Project area wells located on both sides of the fault. Well locations are displayed in new **Figure A-29**. New **Table A-4** displays the Vcl values calculated for each well and the averaged stratigraphic value used in the SGR calculation. Lastly, new **Figure A- 30** shows the Allan Diagram with SGR results and example calculations, using Eq-1, for cross section ID 4. Overall, the Stockton Arch Fault has an average SGR value of 39%, with an average of 38% for the top of the Winters Injection Zone and 41% for the bottom of the Winters Injection Zone. SGR values >20% imply that there is a high chance of fault-zone seal (yielding et al, 2010), therefore, the SGR values calculated for the Stockton Arch Fault in the project vicinity support that the fault is sealing.* *As requested new **Figure A-28** has been added to show a localized structural section displaying a more precise location of the Stockton Arch Fault between wells Sonol_Securities_8 and*	

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				*Moran_1 shown in the **Figure A-27** well correlation panel.*	
2		***Please discuss the cause/nature of the flow barrier and how the flow barrier was modeled.***	Attachment B Section 1.9	*Attachment B, Section 1.9 was updated: "Winters at Union Island is a 300 feet thick lobe of Winters sand with a complex series of sand filled channels with rapid lateral and vertical stratigraphic changes (Hill 1979). The internal barrier in the field is due to these stratigraphic changes, which have a major effect on the hydrocarbon accumulation in this field"*	The First sentence of second paragraph of section 1.9 states that flow barrier is modeled as a no-flow boundary. However, the rest of paragraph suggests that it is not a boundary condition (BC), but rather a change in properties (transmissivity multiplier of 0) that is used to create a flow barrier. ***Please modify or delete the first sentence of the second paragraph to resolve this apparent discrepancy (i.e., an actual internal BC or a material property that creates the flow barrier).*** Note that last sentence of p. B-11 also states that the flow barrier identified at discovery is modeled as a no-flow boundary. ***Again, is it an interior BC, or modified material properties that effectively creates a flow barrier in the model?***
3		***Please provide a detailed discussion on the upscaling process and how the grid resolution was chosen.***	Attachment B Section 1.5	*The third paragraph in Attachment B, Section 1.5, on page B-11 indicated that the model is 9 feet vertical resolution. This text has been updated to "9-foot (averaged, 5-14 feet by proportional layering methodology)".* *It has been confirmed that the grids displayed in **Figure B-4** are from different grids.* *As requested, **Figure B-9** has been updated.*	Comment addressed.

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4a		***Please conduct more thorough uncertainty analysis that includes: Larger range of absolute permeability (e.g., this should be changed by an order of magnitude in each direction);***	Attachment B Section 2.3	*The statement of "An order of magnitude shift is not supported by the project- specific permeability data and transform." is removed. Current permeability multiplier 0.3 to 3 is based on core samples data which were used to generate the permeability transform. During pre-operational testing, site- specific core data will be collected, permeability data will be updated, the model will be updated, and the AoR will be reevaluated.* *The project design is based on CO_2 injection rate control until average reservoir pressure is 4,500 psi, it is also controlled by maximum allowable injection pressure for each injector based on 0.7 psi/ft frac gradient with 10 % safety factor. This dual reservoir pressure control plus maximum allowable injection pressure control strategy ensures that maximum average reservoir pressure and maximum injection pressure limits are not exceeded.* *The first paragraph of Attachment B, Section 2.3 has been updated.*	Table B-8 summarizes the sensitivity analysis cases. ***The description for Case B should say DECREASE rather than increase permeability since it uses a multiplier of 0.3. Please revise the table accordingly.*** Otherwise, responses have addressed previous comments.
4b		***Please conduct more thorough uncertainty analysis that includes: Relative permeability-capillary pressure-saturation function***	Attachment B Section 2.3 Section 1.7	*Attachment B, Section 1.7 has been updated to reflect the following: The computational flow model incorporated the effect of hysteresis on gas relative permeability. Maximum trapping gas saturation of 0.25 is assumed. Imbibition and scanning curves are calculated by the Land's method. The Land's constant C is calculated via the following equation:*	Response addresses how hysteresis was represented in the model, but it does not directly address uncertainty/sensitivity of model results to k-S-p relations other than intrinsic perm and porosity. Sensitivity analyses were performed by perturbing porosities and perms from a reference case. One would expect that entry pressures would also be correlated with perms and porosity if these variables are all related

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				$C = \frac{1}{S_{grmax} - S_{gcrit}} - \frac{1}{S_{gmax} - S_{gcrit}}$ *The trapping function is:* $S_{grh} = \frac{S_{gh} - S_{gic}}{1 + C\,(S_{gh} - S_{gic})}$ *Where* $S_{gic} = S_{gcrit}$ S_{gic}: *critical reversal gas saturation for trapping* S_{gcrit}:*critical gas saturation. It is the gas saturation at which gas first becomes mobile* S_{gh} : *the value of* S_g *when the shift to imbibition occurs* S_{grh}:*maximum trapped gas saturation corresponding to reversal saturation* S_{gh} S_{grmax} : *maximum trapped gas saturation* S_{gmax} : *Maximum saturation* *New figure* ***Figure B-11b*** *has been added to Attachment B.*	through the Leverett-J function. As-is, it seems that one set of S-p curves was used for each of the two facies (sand and shale) represented in the model. ***For consistency with other modeling assumptions, please provide multiple S-p curves with entry pressures that vary with perm/poro, via Leverett J function, rather than a single S-p functions (Fig B-12).*** Sensitivity of model results to variations in the combined/correlated parameters associated with k-S-p relations was not really addressed, but the impact on simulated AOR is probably relatively minor, especially since the caprock was assumed to be basically impermeable. We will consider this comment to be resolved.
4c		***Please conduct more thorough uncertainty analysis that includes: Boundary and/or fault properties (i.e., certainty that the boundary fault is sealing needs to be better demonstrated);***	Attachment B Section 1.9, Section 2.3	*Refer to response #1*	***Refer to reviewers' evaluation #1.***

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4d		***Please conduct more thorough uncertainty analysis that includes: Impact of gas distribution and trapped gas in the initial conditions; and***	Attachment B Section 2.3	N/A	Comment addressed.
4e		***Please conduct more thorough uncertainty analysis that includes: A tornado chart showing relative importance of model variables to dynamic outcomes.***	Attachment B Section 2.3.2	*Attachment B, Section 2.3.2 has been updated to include reference to the Tornado Charts. The Tornado charts are provided as* ***Figure B-28a*** *and* ***Figure B-28b****. These charts mainly focus on storage volume and plume size.*	Comment addressed.
5a		***Please provide more details about how the geological model was populated with heterogeneous parameters.***	Attachment B Section 1.5	*CTV understands. No question related, no response required.*	Comment addressed.
5b		***…Is the interface between the reservoir rock and confining zone treated as a no-flow boundary?***	Attachment B Section 1.5	*Current assumed caprock is water saturated without pressure depletion.* *A mechanistic model was built to evaluate CO_2 leakage to the caprock because of pressure elevation as a result of CO_2 injection,* ***Figure B-3b****. This model includes the caprock formation and Winters Injection Zone. Winters properties are the same as the full field model. Starkey-Sawtooth confining zone properties are based*	Comment addressed.

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				*on Lathrop shale sample MICP data. Average permeability is 0.00098 millidarcy, and the average entry pressure is 1,491 psi. Model results show 5 feet CO_2 leakage vertically from the injection zone into the caprock near the injector, **Figure B-3b**. The total leakage is around 0.002%.* *During pre-operational testing, more site-specific caprock input data will be collected, and the model will be updated, and the AoR will be reevaluated.* *Attachment B, Section 1.5 has been updated to reflect this new model.*	
6		***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.***	Attachment A Section 2.5.4; Attachment B Section 2.3	*CTV understands. No question related, no response required.*	Comment addressed.
7a		The material submitted has insufficient information regarding: ***What is the rationale for using 0.1 CO2 global mole fraction to delineate the AoR?***	Attachment A Section 2.3	*The AoR is delineated using computational modeling which encompasses the region overlying the separate- phase (e.g., supercritical, liquid, or gaseous) CO_2 plume and the region overlying the pressure front where fluid pressures are sufficient to force fluids into a USDW. For CTV II, the storage project is designed to operate at 10 percent below the original reservoir pressure. No pressure exist above the discovery pressure,*	***Please delineate the Area of Review (AoR) according to the four steps described in Box 3-2 on pages 43-47 of***

					the Guidance[1]. Please re-run all the sensitivity analyses to assess the impact on the boundary of this AoR.

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				*0.01 therefore, the AoR is the plume. Comparing the 100 years post-injection boundary of the separated-phase CO_2 in **Figures B-27a** and **Figure B-27b**, the boundary with 0.05 saturation cutoff and the boundary wi01 CO_2 global mole fraction cutoff, the second one is the outmost boundary.* *The project plume boundary is defined by a 0.01 CO_2 global mole fraction cutoff post-injection 100 years, which has 99.99% mass over the total injected mass within the plume boundary. The Project AoR is the project plume boundary plus a 500 feet buffer to address more uncertainty and assure confidence that the corrective action well review accounts for any*	

[1] https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf

				potential impact to USDWs. This is conservative and has been appropriately evaluated.	
7b		*The material submitted has insufficient information regarding:* ***Pressure at the wells and in the reservoir at times before plume stabilization.***	Attachment B Section 2.1	*N/A*	Comment addressed.

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7c		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: comment 2).	None	*Refer to response #2 for additional geological discussion on the flow barrier between the North and South. The critical threshold pressure in Attachment B, Section 3.2.3 and critical pressure in Appendix 10 both refer to "Threshold Pressure Front."*	***Refer to reviewers' evaluation #2.***
7d		The material submitted has insufficient information regarding: ***More simulation results***	Attachment B Section 2.1	*Currently, the flow barrier is not in the geological model. During dynamic modeling, the transmissibility is set as 0 to approximate the impacts of the flow barrier on plume development and pressure elevation.* ***Figure B-17a*** *–* ***Figure B-17e*** *referenced in Attachment B, Section 2.1.1*	Attachment B, Section 2.1 discusses results for different injectate compositions.
8		***Geomechanical modeling is needed because of the presence of the fault. Leakage risk assessment for fault and penetrating wells is also needed.***	Attachment A Section 2.5.3	*EPA Class VI regulations and guidance specify that operators must perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs; however, nowhere is leakage risk assessment modeling recommended or required. The requested leakage risk assessment modeling is beyond the scope of the Class VI regulations and guidance and is not necessary as CTV has evaluated all wells in the AoR, identified those requiring corrective action, and submitted corrective action specifications for each well to EPA for review and approval.*	The applicant states in a response that "Class G Portland cement is widely used in CO_2 EOR wells and has been demonstrated to have properties that are not deleterious with CO_2." Based on internal EPA reviews of recent scientific literature and industry standards, and in consultation with EPA's Office of General Counsel, EPA Headquarters has determined that certain materials, including some Portland cement, are likely not suitable for construction and plugging of injection and in-zone monitoring wells, particularly under potentially corrosive conditions when both water and CO_2 are present.

					Please provide supporting evidence, such as a site-specific corrosion modeling, to demonstrate the adequacy of the Portland cement proposed for construction and plugging of injection and in-zone monitoring wells.

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				CFR 146.92 (b)(5) specifies that plugging material must be compatible with the carbon dioxide stream for injection wells. Class G Portland cement is widely used in CO_2 EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.	
11	Model Suitability	***Please provide equations for how heat transport and residual phase trapping are considered in model simulations in Attachment B.***	Attachment B Section 1.2 Section 1.7	*Attachment B, Section 1.7 has been updated with the following information:* *$S_{gc} = 0$ is the connate gas saturation and $S_{gcrit} = 0.05$ is critical gas saturation at which gas first becomes mobile.*	Comment addressed.

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13		***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***	Attachment A Section 2.3	*N/A*	Attachment A, Section 2.3.2 has been updated to address the comment.
13a		***Additional questions about the SAF sealing properties:*** ***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?***	Attachment A Section 2.3	*Refer to response #1.*	Attachment A, Section 2.3.2 has been updated to address the comment.
13b		***Additional questions about the SAF sealing properties:*** ***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.***	Attachment A Section 2.3	*Attachment A, Section 2.2.1 was updated with new **Figure A-13** which shows the locations of the wells used to pick well tops for the structural model and to create finalized depth grids.* ***Figure A-26** (former Figure A-23) was updated to display the hanging wall structure. **Figure A-25** was also updated to include the gas water contact, which contact shows in **Figure B-23**.*	Comment addressed.

13c		***Additional questions about the SAF sealing properties:*** ***Please provide information from the previously drilled wells about the presence or absence of hydrocarbons in the hanging wall.***	Attachment A Section 2.3	*Localized trace gas is not indicative of a hydrocarbon column, as shown by the petrophysical log response in the Moran-1 well. The trace amount of gas that was never put on production in Moran-1 points to a lack of connection to the much larger accumulation across the fault at Union Island gas field. To monitor the Lathrop Sands in the hanging wall of the Stockton Arch Fault, new Eastern Fault Block monitoring well M-2 has been planned.*	Comment addressed.
14a		***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.)***	Attachment A Section 2.3	*Refer to response #1*	Comment addressed.

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14b		***Show original gas-water contact (OGWC) to explain how the trap works, especially because the top reservoir map does not close.***	Attachment A Section 2.3	*Refer to response #1*	Comment addressed.

14c		***Explain why some figures show an antithetic fault to the SAF, but others do not. An antithetic fault will change***	Attachment A Section 2.3	*Refer to response #1. The Antithetic Fault was mapped as part of the process mentioned in response #1, which is also described in further detail in Attachment A, Section 2.2.1. The Antithetic Fault is displayed in **Figure A-26** and does not affect the SGR calculations.*	Antithetic faults are shown in Figures A-21, A-22, A-26, and A-30, but not in Figs. A-25, A-27, A-28, A-29, A-33, A-34, A-36, A-38, etc. In Figure A-26 antithetic fault is shown in cross section, but not on plan view inset map. Inconsistencies in plotting led to this comment. ***The reviewers are assuming that some or most of these faults are hypothesized but not necessarily mapped and not necessarily shown in some figures because they are not visible and/or do not extend to ground surface. Is this assumption correct?***
14d		***Provide an Allan diagram of the SAF indicating fluid contact and spill point level.***	Attachment A Section 2.3	*Refer to response #1*	Comment addressed.
14e		***Winters facies change: Why has the shale-out line not been used as a 0- thickness line in the isochore gridding?***		*New **Figure A-16** was added to Attachment A to show the Winters Sands transition to Shale along the northern boundary.*	Comment addressed.

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14f		***Explain why the AoR does not follow the gas field outline.***	Attachment B Section 2.2	*Attachment B, Section 2.2 has been updated, and new **Figure B- 22b** has been added.*	Fig. B-22b shows plan view and cross section plots of simulated trapped and dissolved CO_2. Comment addressed.
14g		***Does the CO_2 plume extend below the OGWCs?***	None	*Refer to response #14f*	Comment addressed.
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.*** ***...Can the flow barrier be seen in seismic profiles?***	Attachment B Section 1.9; Attachment A Section 2.2.2	*CTV understands. No question related, no response required.*	***Refer to reviewers' evaluation #2.***

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16		***Lithology older than the Delta Shale needs to be described.***	Attachment A Section 2.2.2	*Updated Attachment A, Section 2.2.2 has been updated to include more detail on the stratigraphy below the Delta Shale.*	Comment addressed.
17		***The statement of different gas-water contacts (GWCs) at discovery in Attachment B documents needs to be made in the Narrative as well.***	Attachment A Section 2.2.2.	*N/A*	Comment addressed.
18		***Were other locations for the northern boundary considered? (See also sensitivity analysis section of this document.)***	Attachment B Section 1.9	*Attachment B, Section 1.9 was updated to include the response text. New **Figure A-16** was added to Attachment A to show the Winters Sands transition to Shale along the northern boundary.*	Comment addressed.
19	Model Suitability (cont.)	***Please describe the gridding around the injection wells and the upscaling process.***	Attachment B Section 1.5	*The sensitivity analysis results have been added to Attachment B, Section 1.5*	Comment addressed.

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20a- e		***Please provide seismic lines and well correlation panels to explain the following features:*** ***- Regional geological setting;*** ***- Original fluid fill, (both North and South parts of the field) including structural spill point;*** ***- Fault juxtaposition across the SAF;*** ***- Reservoir shale out; and*** ***- N-S divide of the field.***	Attachment A sections 2.2.1 sections 2.2.2 sections 2.2.3	*Refer to response #1. CTV has updated the documentation to demonstrate more clearly how the seismic was incorporated into the model building. Attachment A sections 2.2.1, 2.2.2 and 2.3.2 and associated figures with correlation panels as needed have been added/updated to address the original fluid fill and spill points, fault juxtaposition, reservoir shale-out and N-S divide of field (see response to question #2 also). The regional geological setting is also described in these sections.* *The seismic data are owned by a third party, with CTV leasing the data for internal use. The data are covered by a restrictive license agreement and the seismic model developed from the licensed data is proprietary information. Therefore, CTV are not providing lines showing the seismic data but have attempted to resolve this evaluation through the information and responses described here.*	Request was made to provide seismic lines and well correlation panels. Applicant updated some figures and their description of how the seismic data were used. The applicant did not provide exactly what was requested, claiming proprietary data. However, the applicant's efforts to resolve this without providing more detailed info on seismic data appears to be a good faith effort to address reviewer's questions/comments while still adhering to their perceived constraints. The response is acceptable at this point in the permit application review.
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***	Attachment A and B figures	*The edge was defined using Downey 2010, and the shape was confirmed by seismic data but as discussed it does not provide an exact boundary as the unit shales out. Well logs confirm the shale out line as shown in **Figure A-16**.*	Comment addressed.

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		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.***	Attachment B Figure B-10b.	*Currently, the flow barrier is not explicitly defined in the geological model. During dynamic modeling, transmissibility set as 0 to approximate the impacts of flow barrier on plume development and pressure elevation.*	Comment addressed. ***However, some of the text is still unclear about specifically what was done. If flow barrier was actually being created by assignment of material properties (T=0), rather than by setting an internal boundary condition, please update all relevant text to say so.***
23		***Figure 3.6 of Attachment B: Please display the reservoir shale-out line in the figure.***	Attachment B Figure B-7	*N/A*	Comment addressed.
24		***Figure 3.16 of Attachment B: Will any new wells be drilled for monitoring (e.g., in the north)?***	None	*N/A*	Comment addressed.

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25		***In Attachment A, section 2.2.1, why is the Lathrop formation not listed? (see Appendix of this document).***	Attachment A Section 2.2.1 Section 2.2.2	*Additional information on Lathrop Sands was added to Attachment A Section 2.2.1 and Section 2.2.2*	Comment addressed.
26		***In Figure 2.2-5 of Attachment A, the fault boundary is clear but what determines the boundary downdip? Why has the shale-out line not been used as a 0-thickness line in the isochore gridding?***	None	*Refer to response #21*	Comment addressed.
27a		***Please clarify how well completion was implemented into the simulations.***	Attachment B Section 1.2.8 Section 1.11	*Each injector was incorporated into the dynamic model by well model. The injection well model correlates the reservoir flow rate of phase j (j=gas, water) to the well bottomhole pressure (P_{bh}) and the pressure at grid point. The CMG GEM well model is a generalization of the well model proposed by Peaceman (1987) and Peaceman (1983) for square and non-square gridblocks. The mobility treatment follows the suggestion of Chappelear and Williamson (1981). In addition, the geometric factor allows the determination of the equivalent radius from both the geometry of the grid block and the location of the well in the grid block. Refer to Attachment B, Section 1.2.8*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
				for more details. *Yes, the dynamic modelling and well completion plans are consistent.*	
27b		***Please confirm if the wells are constant-rate injectors subject to a maximum injection pressure.***	Attachment B Section 1.11	*Yes, all injection wells are constant-rate controlled subject to a maximum allowable injection pressure that is based on the fracture gradient with a 90 percent safety factor. Additionally, reservoir pressure will be gradually restored to 10 percent below the original discovery pressure throughout the duration of the project. The injection rate will keep as designed base case of 530 t/day will ensure that the maximum allowable injection pressure will never be reached.* ***Table B-6*** *injection rate shows a range of injection rates from the base case to base case plus 50 percent to capture the flexibility of injection rate given other wells' potential downtime. EPA previous asked the rate range to cover the flexibility.*	Comment addressed.
28	Model Design	***Please explore and provide information on the impact of the northern boundary location, as mentioned in Comment 18 above.***	None	*CTV understands. No question related, no response required.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
29		***In the Appendices (CTV II AoR _CA AoR Delineation.pdf), the plume front is defined by a CO2 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?***	None	*Refer to Response #7a*	
30		***Was a grid sensitivity test performed? What metrics did the applicant use to decide this grid was "adequate resolution for plume development"?***	Attachment B Section 1.5	*Attachment B, Section 1.5 has been updated. The full field model, geological model has an average vertical resolution of 5 feet. During the Sector model grid designing analysis, the finest resolution used is average 3 feet.* ***Figure B-4*** *is the surface map from two grid system. It shows similar trends.*	Comment addressed.
31		***Please explain distribution of cell heights.***	Attachment B Section 1.5	*Attachment B, Section 1.5, indicated that the model is 9 feet vertical resolution. This has been updated to "9-foot (averaged, 5-14 feet by proportional layering methodology)".*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
32		***Please provide a table in the document with all this information for all the formations included in the dynamic simulation model.***	Attachment B Table B-3	*Full field dynamic flow model only included the target injection zone, which is the Winters Formation. A mechanistic model sensitivity analysis shows total leakage from injection zone to caprock is around 0.002%. The Caprock property is based on Lathrop shale samples MICP data, which has average permeability of 0.00098 millidarcy and entry pressure of 1,491 psi.*	Comment addressed.
33		***Please explain why no preferential pathways for fluid movement were incorporated into the dynamic fluid flow model.***	Attachment B Section 1.5	*CTV understands. No question related, no response required.*	Comment addressed.
34		***Please provide plots or tables of the time-history of well pressures from discovery to present day.***	Attachment B Section 1.10	*Updated Attachment B, Section 1.10*	Comment addressed.
35		***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***	Attachment B Section 2.	*CTV understands. No question related, no response required.*	***Please delineate the Area of Review (AoR) according to the four steps described in Box 3-2 on pages 43-47 of***

					the Guidance[2].

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
36	Model Design (Cont.)	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 CO2 mole fractions reaching the fault.	Attachment B Section 2.	*N/A*	Comment addressed.
37		***Please show the pressure throughout injection in plan-view and/or side view. This information needs to be included in more detail.***	Attachment B Section 2, Figure B-21	*N/A*	Comment addressed.

[2] https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf

38		***Please clarify what time step values were used in the simulation.***	Attachment B Section 1.13.	*CTV understands. No question related, no response required.*	Att. B, Section 1.13 notes the timestep sizes.
39		***Please review the choices of boundary conditions for the delineation of the AoR and evaluation of plume stability.***	Attachment B Section 1.9, Section 2.3	*Refer to response #1, #4, and #5.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
40	Input Parameter s vs Site-Specific Conditions	***Why is there an omission of dissolved gas in the liquid phase between the current gas/water contact and the original gas/water contact?***	None	*CTV understands. No question related, no response required.*	***Refer to the reviewers' evaluations #1 and 13b.***
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.***	Attachment B Section 1.10	*Text has been added to Attachment B, Section 1.10.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
42		***Please provide maps of permeability and porosity at different angles than Figure 3.9 of Attachment B.***	Attachment B Figure B-10b.	*N/A*	Comment addressed.
43		*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.*	None	*N/A*	Comment addressed.
44		***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.***	Attachment B Section 1.7	*CTV understands. No question related, no response required.*	Comment addressed.
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.***	None	*Refer to response #5b.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
46		***Please clarify whether the model included a geothermal gradient.***	Attachment B Section 1.10.	*Temperature gradient is 0.0159561 °F/foot, the maximum temperature difference is less than 5 °F compared to the base case in the target zone. When adding a geothermal gradient, the storage volume and plume size will reduce approximately 1%. Please refer to **Table B-8** of Attachment B. Attachment B, Section 1.10 has been updated*	Comment addressed.
47		***While pressure is expected to remain lower than discovery conditions, analysis of potential for fault reactivation is needed, from a risk assessment perspective.***	Attachment A Section 2.5.3	*N/A*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
48		0.7 psi/foot fracture gradient is assumed for the injection zone at present. ***Please provide a rationale for this assumption.***	None	*N/A*	

49		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?***	Appendix 10, Attachment A Section 2.3	***Figure 2a*** *in* ***Appendix 10*** *shows the reservoir pressure distribution at the end of the injection.* ***Figure 2b*** *in* ***Appendix 10*** *shows the reservoir pressure increase distribution at the end of injection to start of the CO2 injection.* ***Figure 4*** *in* ***Appendix 10*** *shows the reservoir pressure difference distribution at the end of injection and discovery. Based on project operational design, injection will stop when the average reservoir pressure reaches 90% of the discovery pressure of 5,040 psi. No place has pressure above discovery occurring. Because of the flow barrier between North and South, the pressure build up is different in both sides. CTV has updated* ***Appendix 10****, the first paragraph on Page 2****. Attachment B Figures B-21 and B-22*** *provide additional documentation of model simulated pressure build up including north and south of the flow barrier.*	Comment addressed. ***However, please update Appendix 10 by:*** • ***displaying in a table all the parameters, including the initial pressure in the injection zone, used for calculating the threshold pressure,*** • ***showing the injection well locations on Figure 3, and*** • ***providing pressure contour lines on Figures 3 and 4.***

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
50		***Please show the injection well locations in Figure 2 of Appendix 10.***	Updated Appendix 10 Figure 2	*N/A*	Comment addressed.
51		***Please provide equations for how mass transport is considered in model simulations in Attachment B.***	Attachment A Section 1.2	*N/A*	Comment addressed.
52		***In the Narrative, it is stated that the "CTV forecasts the potential CO2 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?***	Attachment A Section 1	*Attachment A, Section 2.10 was updated with the following information: The Lathrop gas reservoir located approximately 4 miles east of the Union Island gas reservoir provides a fair comparison based on similar geology. Cumulative gas production from the Lathrop gas reservoir is 365 bcf plus minor water, while cumulative gas production from Union Island gas reservoir is 292 bcf plus minor water. Using the Stanford University methodology CTV expects the Union Island Gas Field to have a similar CO2 storage capacity as the Lathrop Gas Field. This methodology shows that the dynamic model predicted storage volume of 22.7 million metric tons (MMT) is conservative.*	Response does not directly address the question/ discrepancy regarding length of planned injection (23 or 24 years). ***Please clarify the length of planned injection.***

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
53	Description of Computational Modeling Results	***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***	Attachment B Section 2.	*A scale has been added to **Figure B-15a and Figure 15-b** as requested.* *__Figure 2b__ and __Figure 4__ added in Appendix 10 The model is controlled by CO_2 injection rate until average reservoir pressure is 4,500 psi. At the end of injection, the highest pressure is around 200 psi below the original reservoir pressure.*	***Scales added to Figures B-15a and B-15b show CO_2 concentration units of ft, with a range from 2 to 343 ft. This is not a concentration unit. This needs to be addressed.*** ***Also refer to the reviewers' evaluation #35.***
54		***Regarding the reservoir pressure, section 3.2.2 of Attachment B indicates that "For both injectate scenarios, CO2 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?***	None	*For the 100% CO_2 injection case, the maximum injection pressure for each well is 4,259 psi /4,306 psi/4,286 psi/4,887 psi/4,870 psi for INJ-1 /INJ-2 /INJ-3 /INJ-4 /INJ-5 respectively. Which is significantly below the maximum allowable injection pressure.* *Yes, the project design is based on CO_2 injection rate control until the average reservoir pressure is 4,500 psi. It is also controlled by maximum allowable injection pressure for each injector based on 0.7 psi/ft frac gradient with 10 percent safety factor. This dual reservoir pressure control plus maximum allowable injection pressure control strategy ensures that maximum average reservoir pressure and maximum injection pressure limits are not exceeded.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
55		*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.***	Appendix 10	*N/A*	Comment addressed.
56		*The modeling results only reflect the extent of CO2 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.*	Attachment B figures	*CTV understands. No question related, no response required.*	***Refer to the reviewers' evaluation #35.***
57		*No plots or tables are shown that directly indicate that the simulation*	Attachment B figures	***Figure B-20b*** *represents the base case with injection rate 10MMSCF/day vs. Injectate 1 and Injectate 2 with the same injection rate specified.* ***Table B-6*** *injection rate is base case to base case plus 50% to capture the flexibility of other wells potential downtime. 10MMSCF/day equivalents the 530t/day. Cumulative injection for each injector is added to* ***Figure B-20b****.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
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.*	Attachment B figures	*N/A*	***Refer to the reviewers' evaluation #35.***
59	Model Calibration and Sensitivity Analyses	*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.*	Attachment B Section 2.3	*N/A*	Comment addressed.
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%.***	Attachment B Section 2.3	*Refer to response #4a.*	***Refer to the reviewers' evaluation #4a.***

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
61		***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.***	Attachment B Section 2.3	*Sensitivity scenarios run with capillary pressure increasing 30% and reducing 30% based on the base case. This results in storage volume changing by 1.8% to 1.9% and plume size changing by -1.4% to 2.2%.* *Table typo corrected.* *Attachment B, Section 2.3.2 has been updated.*	Comment addressed.
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***	Attachment B Section 2.3	*N/A*	Comment addressed.
63	Model Calibration and Sensitivity Analyses (cont.)	***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.***	Attachment B Figure B-23	***Figure B-23*** *has been updated with cumulative gas production bubble scale. scCO_2 plume boundary is defined by 0.05 gas saturation cutoff 100 years post injection. CO_2 plume is defined by 0.01 CO_2 global mole fraction cutoff 100 years post injection. Gas water contacts were determined from logs combined with production results.*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
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.***	Attachment B Section 1.5	*Refer to response #30*	Comment addressed.
65	**General Comments**	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 CO2 storage and could also negatively impact injectivity.	See response to Question 6	*N/A*	Comment addressed.
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.	See response to Question 30 and 61	*N/A*	Comment addressed.
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.	See response to Question 7c	*Refer to response #2*	***Refer to the reviewers' evaluation #2.***

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
68		Geomechanical modeling is needed especially for the fault, leakage risk assessment for fault and penetrating wells.	See response to Question 8	*Refer to response #1 and #8*	***Refer to the reviewers' evaluation #8.***
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 CO2, but also formation brine is also a	Attachment B figures	*Please see **Figure B-21** and **Figure B-22a** for pressure distribution.* ***Figure B-22b** added to show CO_2/gas and CO_2/brine interface over time.*	Comment addressed.
70		Additional analysis of the closed northern boundary assumption is needed.	See response to Questions 18 and 28	*CTV understands. No question related, no response required.*	Comment addressed.
71		Quantitative discussion of upscaling to 200x200 m simulation grid is recommended	Attachment B Section 1.5	*The information on upscaling and local grid refinement discussion has been added to Attachment B, Section 1.5*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
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.	See responses to questions 35, 37, 53, 56 and 58	*N/A*	Comment addressed.
73		Additional uncertainty simulations with a larger range of absolute permeability are needed.	See response to Question 4	*N/A*	***Refer to the reviewers' evaluation #4.***
74		Simulations including trapped gas below the present water/gas contact are needed	Attachment B Section 2.3	*Different trapped gas saturation, residual gas saturation sensitivity analysis done to evaluate how the CO_2 trapping affects the plume sizes. Refer to Attachment B, Section 2.3 for a detailed discussion.*	Comment addressed.
75		A grid sensitivity study would be helpful.	See response to Question 30	*N/A*	Comment addressed.

#	Section	Comment/Question for company	Report Section Updated	Response (December 2024)	Reviewers' Evaluation of Company's Responses
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.	See response to Questions 1, 13, 14, 20 and 49.	*Refer to response #1*	***Refer to the reviewers' evaluation #1.***
77	Corrective Action Assessmen t	N/A	Attachment B Section 3.5	*N/A*	N/A