

Summary and Response to Public Comments

A draft of the *Methodology for the Quantification, Monitoring, Reporting, and Verification of Greenhouse Gas Emissions Reductions and Removals from Carbon Capture and Storage Projects* was developed by ACR.

All methodology modifications, whether developed internally or brought to ACR by external parties, undergo a process of public consultation. Comments and responses are documented here. Due to the nature of the updates, this new version also underwent scientific peer review prior to approval.

#	ORGANIZATION / COMMENTER	COMMENT	AUTHOR RESPONSE
1	Advanced Carbon Storage Inc.	In acc. to London convention 2019 annex 1 there is still option to store CO ₂ in the ocean in subseabed geological formation which your method lacks it.	The Methodology was updated to clarify that offshore projects must be in the jurisdictional waters (i.e., Exclusive Economic Zone) of the United States and Canada. Storage within jurisdictional borders is required to ensure regulatory oversight of project activities. Storage in only the following offshore geologic storage reservoirs is allowed: saline reservoirs, depleted oil and gas reservoirs, and producing oil reservoirs. Storage in ocean water is not eligible.
2	Anew	Is it possible for a single CCS project to operate in and allocate emission reductions to multiple markets, i.e., generate both ERTs and LCFS credits from separate	Per Chapter 10 of the <i>ACR Standard</i> , double counting and double issuance for the same GHG emission reduction or removal is not allowed.

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		<p>CO₂ sources sent to a single capture facility?</p> <p>Building on the above comment, can a single CCS project generate both ERTs and LCFS credits from the same CO₂ source?</p>	<p>Due to the risk of reversal and need to compensate for a release of stored CO₂, CCS projects are not eligible for simultaneous registration on ACR and another GHG crediting program.</p>
3	Anew	<p>Anew recommends the inclusion of emissions from sustainable or renewable biomass sources in the list of eligible CCS project components. This could be evidenced through the registration, certification, or qualification of the biomass as sustainable or renewable, under jurisdictional or host country standards, regulations, or programs such as the U.S. EPA Renewable Fuel Standard. The CDM EB 23 Report Annex 18: Definition of renewable biomass could also be used to demonstrate eligibility.</p>	<p>New Appendix D (Sustainable Biomass) of the Methodology outlines certification and other requirements for biomass to be eligible for use as a fuel or feedstock in a CO₂ source.</p>
4	Anew	<p>Footnote 2 states that “potential negative carbon accounting” is not in BECCS projects in Version 2.0. What is ACR’s reasoning behind this exclusion, and can ACR provide examples of negative carbon accounting that cannot be included within the project boundary?</p>	<p>The Methodology has been modified to better differentiate between emission reductions and removals. To qualify as a removal, a CCS project must either deploy DAC or capture CO₂ from sustainable biomass as defined in the Methodology. Removal credits are labeled as</p>

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	Carbon Engineering & 1PointFive	<p>CE and 1PF strongly support the differentiation of removals and reductions within the methodology as well as explicit labeling of the geological storage type for the crediting pathway:</p> <ul style="list-style-type: none"> • Credits should have storage type clearly identified (saline aquifers, depleted oil and gas reservoirs, EOR) to provide transparency to customers. Several customers have expressly indicated a preference for DACCS (stand-alone sequestration without any connection to existing or future CO₂-EOR storage infrastructure). • Removals and reductions/avoidance need to be distinguished within the methodology as well as broader carbon markets. Removals are a critical pathway for net-zero plans, and they need to be distinctly identified for buyers. Distinguishing removal credits enables claims that specify the use of removal credits (e.g., SBTi Net Zero). • Differentiation between reductions and removals will likely prove critical in meeting market demand. Already, a growing set of corporate customers have pledged to "go beyond offsets" and to procure physical CDRs to compensate for the emissions they cannot mitigate within their 	<p>such on the ACR Registry.</p> <p>Eligible CO₂ sources and geologic storage reservoirs are separately listed in Table 1 and any combination of the two categories is eligible and shall be disclosed in project documentation.</p>

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		<p>own activities.</p> <p>CE and 1PF suggest the differentiation could be supported in several ways:</p> <ul style="list-style-type: none"> • Separate equations for removal credits and reduction credits • A clear table that describes the activity and the credit category. 	
	Climeworks	<p>We encourage further work to better differentiate emission reduction credits and carbon removal credits. Amongst others, the IC-VCM clearly lays out the need to differentiate between the two.</p> <p>With the chosen approach, Climeworks does not see a necessary differentiation of emission reductions and removals installed (e.g. compare draft CCPs by the IC-VCM). Eq. 32 (setting BE_y as the amount of emissions captured by a DAC facility) will not result in CDR projects to have a net negative value. This will not help scale CDR as a sector, as outcomes might be misunderstood as equivalent to emission reduction activities, which they are clearly not. One helpful precedent that has given a lot of thoughts on the topic of baseline emissions / reference for DAC (and other CDR) related activities is the European Union with the Innovation Fund methodologies. Please</p>	

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		consult their approach . Generally, we welcome further differentiation between emission reductions and removals throughout the document.	
	Drax	Clearly distinguish between removal / reduction components: While we believe both removal and reduction carbon credits of high-integrity can have their merits, these are fundamentally different in their nature, use cases, and hence market value. As an example, SBTi only allows for the use of removals credits in achieving Net Zero targets. The value of removal credits may become diluted when associated directly to reduction credits. Hence we would recommend two adjustments in order to incentivize removal players to use your methodology i) we strongly suggest to split the methodology in two components, one for removal and one for reduction ii) in line with ICVCM’s principles, we would suggest that each removal credit is tagged as such in the ACR registry.	

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5	Anew	This section states that “active projects that undergo a significant operational change that increases project capacity” are eligible to participate and can tie the project start date to the operational change. Given the significant capital costs and planning involved, would new pattern injection at an existing EOR project qualify as a significant operational change?	<p>The quoted/referenced text has been removed from the Methodology and replaced with more specific eligibility requirements in Section 2.III: “CO₂ storage must occur at a new geologic storage reservoir (i.e., be newly storing CO₂ from source(s) listed in Table 1). CO₂-EOR projects moving from geologically sourced CO₂ to one of the sources listed in Table 1 are eligible for the periods noted in Section 4.3 (Temporal Boundary).” The updated language still allows for an increase in CO₂ capture over time.</p> <p>Projects are subject to the Start Date requirements outlined in the Methodology and the <i>ACR Standard</i>.</p>
	Carbon America	Supportive of the clause to allow inclusion of additional project capacity following a significant operational change. Not only does this allow for and encourage increasing capture over time, we expect many projects may start smaller and ramp up.	
	Climeworks	On III. Be a new CCS Project or a project addition which will increase project capacity. Climeworks welcomes standards to remain open to existing projects, especially for DAC projects. Given the novelty of this approach, existing factories that might have foremost served a prototyping or engineering exercise would benefit of more openness towards integration within the standard. We’d welcome such changes, given that it continues to be safeguarded that no double counting and additionality remain in place.	

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	Oxy	The methodology should encourage the expansion of both existing and new CCUS projects, but it is unclear whether the current framework is optimized for one or the other. Suggested Revision: Clarify the intended scope of the methodology to support both the expansion of existing CCUS projects and the development of new projects, ensuring incentives and requirements align with both pathways.	
	Radicle	“Be a new CCS project...” Suggest clarification of what is meant by CCS. Does that include EOR activities? Or do you mean Dedicated Deep saline Aquifers only? Suggest clarify the word “new” by delineating a start date which would indicate “new,” i.e projects that start construction after November 1, 2022.	
6	Anew	The second sentence of section 3.2 implies that a project must pass a “three-pronged additionality test” as part of the performance standard approach. Section 4.B of the ACR Standard V7.0 states that ACR recognizes the performance standard approach “in lieu of the three-prong test.” Please confirm whether a CCS project must also apply the three-prong test for additionality, including common practice and implementation barriers, if it meets the performance	Section 3 (Additionality Assessment) has been updated to clarify that, to qualify as additional, a project must pass the regulatory surplus test and (1) either meet or exceed the applicable performance standard, <i>or</i> (2) satisfy the three-pronged additionality test. The latter only applies to specific types of CO ₂ -EOR projects.

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		standard as described in section 3.2.2.	
	Summit Carbon Solutions	The methodology has some inconsistencies in the wording in the Additionality section. The opening section states the need to pass a three-pronged additionality test but then only specifically calls out the regulatory surplus and performance standard requirements. Making this section more consistent across all three tests would make things more clear for Project Proponents.	
7	Anew	It is unclear how projects that are required by regulation but exceed the regulatory capture requirement (second paragraph of section 3.2.1) can meet a practice-based performance standard. Anew recommends the inclusion of a regulatory emissions rate or benchmark in the performance standard (section 3.2.2) for clarity.	Section 6.1 (Baseline GHG Emissions) clarifies that the intensity-based baseline approach can be used only when the CO ₂ source is subject to a legally enforceable emissions intensity limit. Projects that meet the regulatory additionality requirement (through demonstration that the CO ₂ source(s) exceeds regulatory requirements) and meet or exceed the performance standard must use this approach to baseline emissions accounting when it is the most conservative of the two baseline calculation options.

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8	Anew	<p>Anew asks that ACR consider relaxing the requirements for the Risk Mitigation Covenant and/or the acceptable alternative risk mitigation assurances, especially with respect to pore space owners that are not the Project Proponent. The post-project term requirements for CO₂ storage, as written, may hamper project development and, in many cases, agreements with landowners for pore space access are already in place. Anew recommends that ACR apply mitigation responsibilities solely to the Project Proponent, provided the Project Proponent can demonstrate pore space access to ACR's satisfaction.</p>	<p>The Methodology has been updated to require a CCS Project Reversal Risk Mitigation Contract between ACR and the Project Proponent. This contract prevents, provides for the discovery of, and ensures compensation for activity that may result in a reversal. ACR acknowledges that Project Proponents may have to revise agreements with landowners and/or rights holders, and notes that these requirements are in place to ensure the permanence of GHG emission reductions and removals.</p>
9	Calpine	<p>Calpine is working on or considering several CCS projects that will reduce the carbon-intensity of power, steam and other products, by means that do not fit within the Methodology's definition. Such projects may include permanent sequestration in basalt formations and in industrial byproducts and products such as concrete, plastics or other media that will result in less carbon being released into the atmosphere. We note that ACR includes a footnote on Table 1 that mineralization and enhanced weathering may be considered in the future. Calpine is supportive of this and additional expansion of eligible methods that prevent CO₂ from entering the</p>	<p>ACR has limited this methodology to geologic carbon storage in specific geologic storage reservoirs due to their well-documented reliability for long-term storage and the recognized need for this technology to meet global GHG emission reduction targets.</p>

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		atmosphere.	
	Climeworks	We welcome further developments of the methodology to include mineralization as a storage pathways. This can be done above ground: E.g. see the approach of the Swiss company Neustark, or below ground, as evidenced with the world’s largest DAC facility currently in operation, where the Icelandic company Carbfix is sequestering via a rapid mineralization process in basaltic reservoirs.	
10	Calpine	Methodology includes a number of requirements that are intended to limit the potential for carbon-controlled, fossil-fueled, generation to be dispatched on a more regular basis. While it is clear, any policy that incentivizes carbon-intense industry to produce more carbon does not support climate change goals that is not the case here. A power grid that relies on intermittent resources, such as wind and solar, must be supported by efficient dispatchable resources such as fast-start gas and, to a lesser extent, batteries. If such dispatchable resources do not release carbon into the atmosphere, the net effect is a much lower carbon-intensity for the grid. As these carbon-controlled resources run more they will displace	The comment may be based on a misinterpretation of the requirement that project-based baseline emissions be assessed for the same level of use output as occurs without the addition of carbon capture on a CO ₂ source. The language has been clarified and the Methodology states that baseline emissions must account for the parasitic load that the addition of carbon capture contributes to a CO ₂ source. The methodology does not prescribe or proscribe specific energy sources for CO ₂ sources or project operations, but does outline how the GHG emissions associated with those energy sources must be accounted for.

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		<p>less efficient and more carbon-intense resources, further supporting climate change goals. In addition, high temperature industrial heat, in the form of steam, represents one of the most difficult industrial areas to decarbonization. Power generating resources that are carbon-controlled, which also provide high temperature heat, Combined Heat and Power Generators (Co-Gens), are unique in their ability to reduce climate pollution related to high temperature heating. It is a mistake to assume that these resources could be replaced by intermittent resources that produce less carbon. Therefore, an effective carbon accounting scheme should recognize the unique potential environmental benefits these carbon-controlled units bring. It would again seem that the environment and the Methodology would benefit from more flexibility.</p>	

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11	Calpine	<p>Calpine believes it prudent that the Methodology align with the requirements of Section 45Q of the IRS tax code as much as possible for U.S.-based projects. The Methodology includes a number of requirements that may create inefficiencies in project execution and operation. In most cases, these differences can be eliminated in favor of a more efficient and effective program. The time periods for certification and post-injection monitoring is one example of the differences between the Methodology and 45Q. Specifically, 45Q currently compensates a CCS project for the CO₂ captured and sequestered over a 12-year period which remains sequestered for no less than three years after the last injection of CO₂, but the Methodology proscribes a 10-year certification with a five-year renewal and five years of post-injection monitoring. To date, the industry has developed in response to the requirements of 45Q. As just a few examples where 45Q has driven project development, insurance companies have developed 12+3 products that financing parties require; transportation and sequestration agreements are starting to standardize around these requirements and property agreements at the sequestration sites have financial terms that match up with the anticipated revenues timeliness outlined in 45Q. If a different method, such as the</p>	<p>The Methodology was updated with Crediting Periods of 12 years for non-direct air capture (DAC) storage in any geologic storage reservoir and 15 years for DAC projects that do not utilize CO₂-EOR. The 12-year Crediting Period aligns with the U.S. 45Q tax credit period. Projects that do not utilize CO₂-EOR are eligible for Crediting Period renewal. There is otherwise no limit on Crediting Period renewals for non-EOR projects.</p> <p>ACR does not find it appropriate to align post-injection monitoring (to ensure the permanence of carbon credits) with the requirements for tax credits (to stimulate investment in the technology).</p>

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		<p>current draft of the Methodology, were introduced, all of those agreements would likely have to be modified to reflect those timelines or else risk not having legal requirements match up with the commercial requirements. Put another way, it is not clear how project economics could support a 20-year project timeline (10+5+5) when it was designed to support a 15-year timeline (12+3). We believe that this inefficiency, and others like it, would likely dissuade otherwise eligible projects from participating in the ACR marketplace.</p>	
	Climeworks	<p>We applaud the acknowledgement of long timeframes (30+years) to qualify a CCS project. For novel CDR technologies such as DAC, the economic viability remains challenging and with limited governmental action on CDR (at scale), we foresee a longer crediting period for CDR projects (i.e. BiCRS and DAC) justified. I.e., for CDR activities we welcome crediting periods that go beyond the foreseen 10 years, e.g. between 15-25 years, in order to safeguard and hedge the additional upfront investments needed to start projects. This request is limited to CDR project’s crediting periods. Given the urgent need to abate fossil fuel emissions and the political momentum for such activities, a 10 year crediting</p>	

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		<p>period seems justified for CCS projects leading towards emission reductions.</p>	
	<p>Drax</p>	<p>Crediting period is too short: As you note yourselves, “CCS projects are usually long-term (30+ years) and involve significant investment”, before concluding that the crediting period should only be 10 years. This is not a sufficiently long timeframe to give investors and financiers confidence to move ahead with billions of dollars of investments. We believe at a minimum this period should be 20 years to incentivize scale-up.</p>	
	<p>Ozona</p>	<p>It is stated that since most of the CCS projects are long term (30+ years) that the crediting period shall be 10 years. Rather than the somewhat arbitrary 10 years, we think it should be 12 years to match the term of the 45Q. Otherwise, 10 years into a 12 year project a renewal would be required.</p>	
	<p>Phillips 66 Company</p>	<p>The crediting period length in the ACR CCS protocol is 10 years. Many CCS projects will rely on 45Q credits and the crediting period under that provision is 12 years. Considering CCS project funding decisions will be made with a time horizon of 25+ years, it will be beneficial to align the ACR CCS protocol crediting period with 45Q at 12 years.</p>	

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	Radicle	10 year crediting period with the possibility of renewal is too short given the investment required. Certainty of longer term credit generation is required for a strong economic case. Precedent for longer crediting period exists in Alberta compliance market under TIER for these activities which is set at 20 years with the possibility of 5 year extensions.	
12	Calpine	The Methodology includes a few requirements that may be best dictated by other market participants: project insurance products, geology of a sequestration site, Class VI well design, and type and tenure of title to land at a sequestration site. While these aspects are a critical part of every project, they are often dictated by others who are more directly involved in a project such as financing parties, regulators, permitting agencies and project partners. It would be unfortunate if a CCS project were found to be ineligible for participation in ACR simply because a regulator required a different, or possibly more stringent, methodology than ACR's. To avoid such a scenario, it seems that the Methodology, and the environment, would benefit from more flexibility to ensure that captured carbon is permanently sequestered.	Underground injection and other regulations can vary greatly between nations and subnational jurisdictions and may not have the same interest in permanence that the carbon market requires. Section 2 (Eligibility Conditions) was updated to explicitly require that projects in the U.S. must obtain either a Class II or Class VI Underground Injection Control Permit. Methodology Section 7.3 (Monitoring, Reporting, and Verification (MRV) Plan) was updated extensively to align with U.S. EPA Class VI MRV requirements, regardless of permitting classification or jurisdiction. Allowing flexibility for projects to choose from different underground injection permit schemes provides flexibility while ensuring the consistent carbon credit rigor.

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	CarbonVert	For improved efficiency, recommend stating that any of the following would meet the requirements of their MRV: IRS MRV Plan, ISO Standard for monitoring, BSEE/BOEM requirements, Class VI requirements.	ACR finds it appropriate to have the same MRV requirements of all CCS projects. This establishes a consistent, robust, and high-integrity standard for all projects. Consistent with the <i>ACR Standard</i> , the Methodology specifies that reversal risk can be mitigated via a legally binding Reversal Risk Mitigation Contract and Reserve Account contributions or an alternative risk mitigation assurance mechanism acceptable to ACR.
	ClimeCo	“All CO ₂ injection wells in the US must meet Class VI well requirements and wells used for EOR operations must meet Class II well requirements outlined by the USEPA underground injection control (UIC) program.” This language introduces confusion as to which well classes are eligible for crediting and suggests that only class VI wells are eligible for pure storage projects and that only EOR project can utilize a class II well for credits. Please modify to make clear that both well classes for storage projects will be eligible for crediting.	
	Drax	<p>Liability transfer, buffers & monitoring: While we appreciate the efforts taken to align the methodology with regulation, we believe you can and should go even further to align the with the stringent requirements which have been developed in leading jurisdictions, in particular:</p> <p>Liability for reversals: Across the EU / UK / US there are incredibly stringent requirements on liabilities and remediation responsibilities faced by storage</p>	

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		<p>operators in case of CO₂ leaks. National / state-level regulatory regimes often specify when / how liability for CO₂ storage is transferred from capture projects to storage owners / operators and eventually to national / state Governments. The requirements in the voluntary carbon market should not cut across those national / state-level frameworks. To exemplify, a capture operator who is the project proponent / eventual credit owner, should not be required to include legal liability for leaks in its contracts with storage operators, as these storage operators are already liable to government to make good.</p> <p>Buffers mandated by regulators: We ask you to please note that across the EU / US there are already highly stringent buffer systems / post-closure funds / industry body funds that are required to set aside money for monitoring, mitigation and compensation. These should be taken into account in any standard to avoid unfair double penalization.</p> <p>Based on the above three points, we believe that a project developer's liability for the CO₂ should cease at the point of transfer, provided stringent jurisdictional requirements are in place. If needed to provide even further assurances to buyers of carbon credits, beyond the governmental systems described</p>	

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		<p>above, we could also accept to forgo a certain risk-adjusted number of credits at each issuance. These could be conservatively estimated based on scientific evidence, currently established around 0.1-1% for geological storage. We would accept this even while noting it would amount to a doubling up on established government safeguards.</p>	
	Radicle	<p>Suggest stronger language around the requirements for post injection MMV and the standard of acceptable monitoring that is required.</p> <p>Post project monitoring term should more likely be prescribed by the regulatory framework of the jurisdiction proving the pore space tenure agreement or EOR scheme approval. Long term containment and liability must be managed by the jurisdictions allowing the activity. ACR should not be trying to regulate in this space. The requirement should be those that are giving the pore space agreement specify MMV requirements and long term liability requirements.</p>	

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13	Carbon America	We support the inclusion of downstream EOR emissions. As EOR is challenging both from a CI-reduction tracking and public perception standpoint, any additional requirements will boost the strength of this methodology as a whole.	Thank you for your support. Oil produced via CO ₂ -EOR processes eligible under this methodology has a lower carbon footprint relative to other oil production due to the simultaneous injection and storage of non-geologic CO ₂ that would otherwise be emitted to the atmosphere. However, since CO ₂ -EOR enables the production of fossil fuels that will contribute to emissions, and because the projects must demonstrate a net benefit to the atmosphere, the methodology requires that the downstream emissions from the production and use of the oil and associated gas extracted via CO ₂ -EOR are included in the project accounting boundary. This robust accounting ensures that emission reductions credited under the Methodology are a clear demonstration of a net benefit to the atmosphere.
14	Carbon America	We believe the majority of quality, low-risk sequestration opportunities lie in saline geologic sequestration, and that oil and gas reservoirs require an additional level of risk mitigation to address greater opportunities for leakage. We support the inclusion of robust monitoring and reporting	Thank you for your support.

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		frameworks to ensure that these additional leakage pathways are addressed and accounted for.	
15	Carbon America	Reporting period guidelines appear vague. Recommend more detail and more stringent reporting requirements.	The Methodology intentionally allows for flexibility in the duration of a Reporting Period. Reporting Period duration may be set at the Project Proponent’s discretion so long as it does not exceed the maximum set forth in the <i>ACR Standard</i> and the MRV requirements in the Methodology. This flexibility allows for more or less frequent reporting and verification cycles coinciding with the issuance of credits for projects.
16	Carbon America	The origination of the standard-based baseline should be clarified. Is this intended to exclusively point to regulations? If a regulation does not exist, does the developer recommend a standard?	The Methodology was updated to clarify that the intensity-based baseline (formerly called the “standards-based baseline”) approach is only used when there is a legally mandated GHG emissions intensity standard for the CO ₂ source.
17	Carbon America	Appreciate the inclusion of renewable electricity as fuel type for this calculation [Equation 11]. We expect renewables to be a key part of many of these projects.	Thank you for your support.
18	Carbon America	We largely support the changes made in this version,	Thank you for your support.

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		<p>particularly the increased requirements for confining zone characterization.</p>	
19	Carbon Counts	<p>We (Carbon Counts and partners) spent the period 2018-2021 working on a somewhat inconclusive project to develop a legal and regulatory framework for CCS in Mexico. From our analysis – as well as previous World Bank analysis – the law, and indeed the Constitution itself, lacks clarity regarding who is the custodian and owner of geologic pore space, whether the responsibility to manage access to and use of that pore space is vested in SEMARNAT, and if so, what regulation could be used to manage this access.</p> <p>As presently constructed, Section 6.5 of the methodology doesn’t really seem to address Mexico specific issues – indeed, Section 6.5 primarily concerns itself with State law in the U.S., whereas in Mexico, subsoil access rights are a federal not state level matter (per the Constitution). So suggest that this section be tidied up a bit to make clear that it primarily describes the U.S. situation, rather than Mexico, so as to avoid misleading readers regarding the situation of access and pore space rights in Mexico.</p> <p>More broadly, we would also suggest ACR take more</p>	<p>Mexico was previously included as an eligible location under the Methodology. The final version limits eligibility to the United States and Canada based on feedback from technical experts and analysis indicating that the regulatory framework for geologic storage of CO₂, along with associated enforcement mechanisms and administrative infrastructure, may not yet be sufficiently developed in Mexico and other locations to ensure the permanence of emission reductions and removals. ACR will continue to monitor and evaluate regulatory requirements in additional jurisdictions for potential inclusion in the future.</p>

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		<p>care in considering the potential implications of extending the scope of the methodology to Mexico. Furthermore, it is also unclear why Mexico should be assessed differently to any other developing country in respect of these matters.</p> <p>Seemingly the barriers faced in Mexico – and in particular the issues in the Constitution itself, which requires primary legislation to fix – are potentially even greater than other countries that also do not have specific CCS laws and regulations. Indeed, many countries have parallel legal frameworks that could be readily adapted to permit CCS activities, at least in early stages of development (for example, countries in Southern Africa, where we have also worked on various CCS regulatory studies). In our opinion, these jurisdictions are could be better prepared to permit CCS activities than Mexico is right now.</p> <p>The legal uncertainty over pore space access in Mexico is likely to significantly impair investment in CCS in the near term. Perhaps ACR offering this carrot might spur them to do something to clarify the legal and regulatory framework. But in doing so, it is worth considering whether similar carrots could also be offered to other jurisdictions.</p>	

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20	Carbon Engineering & 1PointFive	<p>As we understand from the draft protocol, the use of regulatory surplus and performance-based approach supports DACCS projects as additional. It would be helpful to explicitly list DACCS as an additional activity, perhaps using a positive list.</p> <p>The ICVCM Assessment Framework identifies and defines the use of positive lists as an effective means of assessing project additionality. We are supportive of carbon registries, such as ACR, using a positive list to evaluate DACCS projects that are inherently additional by nature. We request the ACR consider specifically allowing DACCS projects to be automatically considered additional in order to encourage new and innovative projects to access carbon finance.</p>	<p>Direct air capture (DAC) is explicitly added to the Methodology as an eligible CO₂ source and is defined as “the engineered and non-biological processes to capture CO₂ from the atmosphere through mechanical, chemical, or physical separation processes.” It is also explicitly eligible under the practice-based performance standard.</p>
21	Carbon Engineering & 1PointFive	<p>The methodology lacks a tailored baseline approach for DAC, instead applying industrial CCS criteria, which does not align with DAC’s unique nature as a removal technology rather than an emission reduction project.</p> <p>Suggested Revision: Introduce a DAC-specific baseline methodology that reflects its true zero-emission baseline instead of assuming avoided emissions.</p>	<p>Section 6 and Equation 3 of the Methodology establish that projects with DAC CO₂ sources must use a project-based baseline approach. The DAC project-based baseline uses the measured quantity of CO₂ removed directly from the atmosphere.</p>

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22	Carbon Engineering & 1PointFive	<p>The current MRV framework lacks clear protocols for DAC-based projects, which require distinct monitoring requirements for carbon capture, transport, and injection into storage sites.</p> <p>Suggested Revision: Develop a DACCS-specific MRV framework, ensuring rigorous CO₂ tracking at all stages, from capture to long-term storage verification.</p>	<p>The Methodology was updated to specify how CO₂ captured from DAC CO₂ sources shall be measured. All other parts of a project with DAC are no different from projects with other CO₂ sources. MRV requirements for all projects are outlined in Section 7.</p>
	ClimeCo	<p>On the project requirements, the pore space proof and land liens in favor of ACR – in the US if the EPA class IV (or class II) permit is approved, doesn't that meet the requirements? Why are these additional requirements added on top of this very rigorous permitting process? These land requirements are too onerous without adding value.</p>	
23	Carbon Engineering & 1PointFive	<p>The methodology does not clearly assign long-term liability for stored CO₂, raising concerns about post-injection monitoring responsibilities and permanence assurances beyond the crediting period.</p> <p>Suggested Revision: Establish a clear liability framework that defines ownership of stored CO₂, long-term monitoring obligations, and accountability for potential leakage risks.</p>	<p>The Methodology has been updated to establish a clear framework for long-term CO₂ permanence and liability. Project Proponents must demonstrate clear and uncontested rights to the storage reservoir pore space and surface access rights, ensuring the ability to conduct long term monitoring and remediation activities. Project Proponents must enter into a Reversal Risk Mitigation Contract with ACR and contribute to the Reserve Account or mitigate reversal risk with an alternative ACR-approved risk mitigation mechanism that serves to prevent, provide for the discovery of, and ensure compensation for reversals. The permanence of the emission reductions or removals is a central tenet of carbon crediting,</p>
	ClimeCo	<p>On the project requirements, the pore space proof and land liens in favor of ACR – in the US if the EPA class IV (or class II) permit is approved, doesn't that meet the requirements? Why are these additional requirements added on top of this very rigorous permitting process? These land requirements are too onerous without adding value.</p>	

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	Summit Carbon Solutions	<p>The methodology proposes a Risk Mitigation Covenant, which would prohibit any planned activity that may result in the release of stored CO₂, secured by a lien in favor of ACR. Summit Carbon Solutions believes that there are multiple options to addressing the potential for reversal risk from future activities that could be considered as alternatives to this approach. For example, North Dakota assigns pore space ownership to the surface owner but mineral rights are separate. Complying with the Risk Mitigation Covenant would require both pore space leasing and the acquisition of all mineral rights in the Area of Review. However, any mineral rights exploration would be permitted by NDIC, which also permits class VI wells for permanent CO₂ storage. NDIC would not permit mineral exploration without the proper safeguards in place to ensure the integrity of the storage complex. Best practices in well drilling can be shown to provide adequate protection. Summit Carbon Solutions recommends further discussions on options to ensure this risk is addressed for CCS projects beyond the Risk Mitigation Covenant.</p>	<p>which is not necessarily true of permitting regimes.</p> <p>Geologic storage reservoir monitoring is required throughout the injection and post-injection periods and may only conclude once plume stabilization is demonstrated in accordance with the Methodology’s MRV requirements. If monitoring indicates that CO₂ is emitted to the atmosphere from the geologic storage reservoir, these emissions shall be measured and reported, verified, and compensated for following the requirements detailed in the Reversal Risk Mitigation Contract and the ACR Reserve Account Terms and Conditions or ACR-approved alternate risk mitigation mechanism.</p>
	Milestone Carbon	<p>The requirements in this provision should be in an agreement between ACR and the Project Proponent, rather than in a covenant filed in the real property</p>	

#	ORGANIZATION / COMMENTER	COMMENT	AUTHOR RESPONSE
		records. Landowners will not support restrictions on the surface of their property and landowners should not have any reporting or compliance obligations to ACR. Remove lien rights in favor of ACR. If Project Proponent does not own the surface/pore space, it may not be possible for ACR to access the property to conduct inspections.	
	Ozona	We agree the operating Company is liable for CO ₂ leaks. We are supportive of the operating Company managing their own risk of loss through insurance products. We do not believe it is the role of the registry to get involved in this.	
24	Carbon Engineering & 1PointFive	<p>The methodology should align CO₂ transport and storage regulations with global best practices such as IPCC guidelines and ISO standards, ensuring consistent and credible implementation.</p> <p>Suggested Revision: Ensure that pipeline emissions accounting, storage site selection, and CO₂ custody transfer requirements align with international regulatory frameworks.</p>	ACR developed a CCS Methodology that aligns with the overarching framework established under Article 6 of the Paris Agreement, requirements of the International Civil Aviation Organization’s Carbon Offsetting and Reduction Scheme for International Aviation, recognized industry standards and best management practices, and the rigor required by both carbon markets, all while ensuring that CCS projects comply with applicable jurisdictional rules and regulations.

#	ORGANIZATION / COMMENTER	COMMENT	AUTHOR RESPONSE
25	Carbon Engineering & 1PointFive	<p>Life Cycle Assessment (LCA) accounting is needed to gain a broader social license to build trust and confidence in the VCM space for DACCS projects. CE and LPF support full cradle-to-grave LCA accounting which would include chemical and energy feedstock streams. Excluding these inputs would not reflect an accurate quantification of the environmental benefit that projects will create.</p> <p>We would like to propose a cradle-to-grave LCA based approach to quantify the net environmental benefit from removal activities. By design, the LCA approach provides a holistic understanding of environmental impact across different life cycle phases of a process or activity. This would reduce subjectivity especially when defining activity boundaries for accounting which are typically broader than the physical boundary of the removal activity.</p>	<p>The Methodology limits GHG accounting to emissions directly attributable to the defined physical and GHG assessment boundaries outlined in Section 4. Upstream emissions from the production of fossil fuels utilized at CO₂ sources and the noted embodied emissions would exist in the absence of the project and therefore fall outside the project boundary.</p> <p>Please also see the responses to comments 52 and 71.</p>
26	Carbon Engineering & 1PointFive	<p>DACCS projects will require large amounts of renewable power to effectively remove carbon dioxide from the atmosphere at a climate relevant scale . However, it is not always possible to co-locate DACCS projects with renewable power resources. Therefore, we propose that ACR consider including guidance in the Methodology that allows DACCS projects to utilize indirect Power Purchase</p>	<p>The Methodology was updated with requirements (in Appendix E, Emission Factor Guidance) for claiming the use of zero- or near-zero-GHG electricity. These requirements include the following: a power purchase agreement) for the electricity resource, the electricity resource must be a newly constructed electricity generator, and any</p>

#	ORGANIZATION / COMMENTER	COMMENT	AUTHOR RESPONSE
		<p>Agreements (PPAs) and a book-and-claim crediting period for the associated environmental attributes of the procured renewable power.</p> <p>The recommended guidance below has been adapted from the California Air Resources Board (CARB) LowCarbon Fuel Standard (LCFS). We believe DACCS projects should be allowed to utilize indirect accounting mechanisms for low carbon intensity (CI) electrical power similar to those allowed for use in innovative technology deployment and infrastructure under the LCFS § 95488.8.</p>	<p>associated renewable energy credits must be retired.</p>
	Milestone Carbon	<p>For purchased electricity (PEElec) consumed by the CO₂ capture equipment where facility operators have entered into renewable or low-carbon power purchase agreements (PPA's) specifically for incremental power consumption, recommend allowing the Emission Factor (E_{Electricity}) in equation 11 to be calculated based on the emissions standards for the source(s) of generation under the PPA.</p>	
	Ruby Canyon Environmental	<p>Complement the end of the third paragraph [in section 4.2.1]: "...such as the project obtaining energy from alternative sources, the Project Proponent is responsible for tracking and reporting electricity and</p>	

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		<p>associated emissions.” with “<u>the task of the VVB is to make sure that the tracking and reporting is reasonable and well documented.</u>”</p> <p>Equation 11, parameter EElectricityEmission factor for electricity generation in the relevant region, by (in order of preference) BAA, eGRID subregion, or State (tCO₂e/MWh). It is suggested to complement the parameter explanation adding the “alternative sources” if applicable:</p>	
	Summit Carbon Solutions	<p>For electricity usage and associated emission factors, the methodology states “If there is any reason to deviate from the use of eGRID emission factors, such as the project obtaining energy from alternative sources, the Project Proponent is responsible for tracking and reporting electricity and associated emissions.” This could be read as allowing for the use of renewable power purchase agreements (PPAs) or virtual power purchase agreements (VPPAs). Summit Carbon Solutions advocates for the use of PPAs within the methodology but recommends that greater clarity is provided on their applicability.</p>	

#	ORGANIZATION / COMMENTER	COMMENT	AUTHOR RESPONSE
27	Carbonvert	<p>“Table 1: Saline formations and depleted or producing oil and gas onshore or offshore reservoirs” Does this mean that the storage site can create the environmental certificate?</p>	<p>If "environmental certificate" is intended to be equivalent to "carbon credit," Table 1 was updated to clarify that CO₂ from eligible CO₂ sources that is stored in listed geologic storage reservoirs are eligible under the Methodology (assuming all other requirements are met).</p>
28	Carbonvert	<p>Add in BSEE/BOEM well construction standards, as they will be the governing body in Federal Waters and will be separate from UIC Class VI.</p>	<p>The Methodology requires that CCS projects follow all applicable jurisdictional regulations and requirements, including all applicable underground injection regulations.</p>
29	Carbonvert	<p>“projects that are inactive at the time of publishing may list within 12 months of publication.” Define inactive. Regulatory compliance with what rule?</p> <p>“Project Proponents may elect a start date at the end of the design phase of a project in order to demonstrate eligibility.” What is the definition of design phase? Is this FID approval, we would want a start date as soon as possible.</p> <p>“Project developers may set their start date to when CO₂ is first injected and would then require a single project validation.” If the start date is at first injection can the environmental credits be issued before that?</p>	<p>This language was removed from the Methodology and the Methodology was updated to clarify that the Start Date for CCS projects may be either the date when eligible CO₂ is first injected as part of a reservoir or pilot test or when injection begins at designed storage capacity. More details on Start Dates are outlined in the <i>ACR Standard</i>.</p> <p>Credits cannot be issued before the project’s Start Date. Under the Methodology, the Crediting Period begins when eligible CO₂ storage begins, excluding any CO₂ injected as</p>

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	Radicle	If the start date occurs at the end of the design phase, then the crediting period is essentially shortened because credit generation will not start until injection begins. Preapproval of the projects to confirm eligibility is a great idea. However, Recommend adding some words to indicate that the clock on the crediting period will not begin until injection begins.	part of reservoir or pilot testing. Since credits are issued only for verified emission reductions or removals that occur during the Crediting Period, no credits can be generated before that point.
30	Carbonvert	Does ACR expect additional compliance capital during the 10-year timeframe or at renewal?	The term “compliance capital” was not in the public comment version of the Methodology nor in the <i>ACR Standard</i> , so ACR cannot respond to the comment.
31	Carbonvert	If emissions become a regulatory requirement during the 10-year timeframe, does that mean that the economic value or pricing of the credit changes? It seems like this is designed to factor in a compliance market emerging for an emissions source.	Regulatory additionality must be assessed during verification for each Reporting Period and emission reductions and removals must be demonstrated to be in excess of what is effectively mandated in order to be issued credits. ACR cannot speak to how the emergence compliance market would impact the price or value of credits.
32	Carbonvert	Define desktop certification between the five-year visits? Is a spreadsheet/dashboard to record/measure/report the metrics needed for emissions calculations. I think the metering and gauging systems at the emitter and storage site will	The Methodology was updated to remove mention of desktop assessment. The procedures and intervals for project site visits are outlined in the <i>ACR Standard</i> and the Methodology requires that the “primary CO ₂

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		capture this.	source site(s); CO ₂ capture, processing, and compression site(s); and CO ₂ injection, storage, monitoring & hydrocarbon production and onsite processing site(s) must be visited as part of each site visit.”
	ClimeCo	A field visit every 5 years may not be sufficient for complex projects. May want to consider rotating annual visits to capture site, transport system, and injection site. To ensure that at least one component of the project undergoes a site visit during each verification, with a complete field visit at a minimum every 5 years, as stated. The initial verification should require a complete field visit.	
33	Carbonvert	Propose the language “verify containment” instead of “assuring no leakage.” It’s difficult to prove a negative. This language is used throughout the protocol.	The Methodology was updated to require CO ₂ plume stabilization instead of an absence of leakage from the geologic storage reservoir.
34	Carbonvert	“The physical boundary demarcates the GHG emission sources.” “The boundary also includes emissions from the transportation, refining, and end use of any hydrocarbons produced through EOR.” I believe this means that if a CCS touches EOR then the boundary is all scope 3 emissions for the EOR oil production.	If a project is producing oil and associated gas as part of injection and storage, the physical boundary includes emissions from the production, refining and processing, transport, and end use of oil and associated gas.
35	Carbonvert	This [Section 2.2] reads to me very similar to CARB and is driving towards something closer to a full Life	The ACR CCS Methodology does not utilize a life cycle analysis, and the use of biomass as a fuel

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		Cycle Analysis. For bio-based processes in particular, does this mean the plant usage of CO ₂ is counted as a “sink”	or feedstock in CO ₂ sources does not count as a “sink.” Instead, sustainable biomass (as defined in the Methodology) is counted as a removal (as opposed to of a reduction).
36	Carbonvert	Is there a missing section on the definition of the Temporal Boundary?	The “Temporal Boundary” section (Section 4.3) of the Methodology was updated to more clearly define Start Date, Crediting Period, Reporting Period, and Minimum Project Term.
37	Carbonvert	Clarify that the ‘baseline’ for new build is due to government regulations, not investment or company expectations, to match later sections.	<p>The final Methodology includes two different approaches (project-based and intensity-based) for baseline determination, neither of which references whether a CO₂ source is newly built. For both approaches, the baseline must be the emissions that would have occurred in the absence of the CCS project.</p> <p>For a pre-existing electricity generation facility, this would be the CO₂ emissions from the facility producing the same quantity of electricity without CO₂ capture. For a new electricity generation facility, this would be the CO₂ emissions from a similar (especially using the same fuel or feedstock) new facility without CO₂ capture producing the same quantity of electricity. For DAC projects, the baseline is the</p>

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			amount of CO ₂ captured by the project, which would have remained in the atmosphere had the project not been implemented. See Sections 5 and 6.1 of the Methodology for more details.
38	Carbonvert	If the CO ₂ is captured/stored in one country, that does not have regulations, and then the product is sold in another, which does have a low carbon requirement, does additionality apply?	Additionality is assessed at the project level, and CCS projects are considered to reduce or remove emissions in the country in which the capture of the CO ₂ emissions occurred (see Section 4.1, Physical Boundary). Baseline emissions and the regulatory surplus test focus on the emitting facility and applicable laws in that jurisdiction, not on regulations in the country where the CO ₂ is stored.
39	Carbonvert	This [Section 4.1.2] is work but, it seems a bit over complicated. I'm not sure why we have a density component, unless they are driving towards eCO ₂ (the rest of the variables to not imply this), and using it as a normalizing factor. BUT, I think this would underestimate if you're using STP and your process is not operated that way. This needs some engineering check on my assumptions. Would it be more efficient/feasible to use mass instead of volume?	The Methodology has been revised to include the option to use mass-flow or volumetric flow measurement for CO ₂ accounting and to make clear that all volumetric measurements must be corrected to standard conditions.

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	Climeworks	Equation 8 foresees CO ₂ transferred_y to be measured via a volumetric flow measurement. In order to allow for some flexibility in approaches, Climeworks favors an additional option of measuring flows via a mass-flow calculation. This is the approach we have successfully implemented at our Orca facility in Iceland. We foresee an either/or approach more meaningful, as long as you can guarantee the validity. VVBs should be able to assess methods too. Note that the same comment applies to eq. 17, 18, 23, 26 and more...	
40	Carbonvert	This section [Section 4.2.1] is confusing to our team. We are counting eCO ₂ , assuming that it will also be vented and should discount the CO ₂ . But, these are not stored components and are often mitigated in other fashions. Can we clarify the logic here. First, most of these processes aren't allowed to emit NO _x , so that should be negated out. Second, CH ₄ is more likely to be flared than anything else, which means that you have an actual CO ₂ emission associated with it. Can we clarify the logic behind this?	All CCS projects must quantify project-related GHG emissions (including CO ₂ , CH ₄ , and N ₂ O), including emissions from venting and flaring. Regarding the reference to NO _x , oxides of nitrogen are different from N ₂ O, which unlike NO _x is a greenhouse gas.
41	Carbonvert	Specific w/ Equation 15. I'm unclear why calculating power inputs into each individual section is the way to go, versus using energy input for the entire project.	The Methodology breaks down the different sources of project emissions into project segment-specific equations because the Project

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		<p>Is the thought that each component is powered separately and therefore needs to be treated differently? It seems like that would make the Boundary setting activities from Chpt 2 more consistent. The only reason I can think of to do it this way, is if there are separate owners for separate components. However, that goes back to the Boundary issues and the true point of an LCA.</p>	<p>Proponent must collect data and retain documentation on each project emissions source, and the Validation and Verification Body (VVB) must review these records. Records very well may come from different operators of different project segments.</p>
42	Carbonvert	<p>Going to need to check my understanding. But, it seems 1) drill through is allowed as long as planned for (really good – CARB doesn’t allow that) 2) pore space/surface ownership can change, again, as long as it’s reported.</p> <p>Feels like this is missing a time frame though – should be tied to something else, but I’m not necessarily sure what. Long term release of financial assurance by EPA? (note here – that money is still available for long term problems, just typically is not housed by the entity anymore. Or at least, is assumed to be. No one has gotten there so far) Termination of the PISC timeframe? Liability has transferred to the long term entity, especially if it’s a government?</p>	<p>The Methodology was updated significantly to clarify the requirements for geologic storage reservoir pore space and mineral rights (see Section 8.2), site access (Section 8.3), permanence (Section 9) and the Minimum Project Term (Section 4.3.4).</p> <p>The intention of the Methodology is for the emission reductions and removals to be permanent, minimizing the risk of reversal and ensuring for compensation of reversals, the specifics of which are articulated within and governed by the CCS Project Reversal Risk Mitigation Contract and ACR Reserve Account Terms and Conditions (or an ACR-approved alternative).</p>

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43	Carbonvert	Clarify why “heat”?	Emissions from thermal energy are included in the project boundary when that energy is used for the project (i.e., the emissions would not exist but for the project).
44	Carbonvert	EIS [Environmental Impact Statements] or EV [presumably EA, or Environmental Assessment] can be provided as a courtesy once approved by NEPA, but ACR doesn’t have comment/audit rights.	ACR requires a copy of the EIS (if required by the jurisdictional authority) for informational purposes.
45	Carbonvert	It’s odd to specify calibration procedures for just two items. In reality, nearly every monitoring technology is going to have calibration procedures. It could make more sense to say that the project is required to submit evidence of calibration of all instruments once per year.	Section 7.2 has been updated to clarify that all monitoring and measurement equipment must be calibrated. It also specifies the standards for such calibration.
46	ClimeCo	Consider modifying language under Applicability I. to allow for shipping industry to participate in CO ₂ capture projects. Transport and Storage applicability conditions already would allow for participation, as written. Ships have expressed interest in capturing onboard CO ₂ emissions for CCS.	The Methodology limits eligible countries to the United States and Canada. Since capture from ships would, in most cases, not occur within these locations, it is not an eligible CO ₂ source in this version of the Methodology.

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47	ClimeCo	<p>“Emissions from the transportation, refining, and end use of produced oil are considered project emissions and must be quantified. These emissions shall be included as project emissions beginning five years after the project start date for January 1,2030, whichever is first.” Unclear as to justification of waiting period. Assume grandfathering existing projects. Should new EOR projects also receive grace period? Please clarify.</p>	<p>The Methodology was updated to account for emissions associated with production, refining and processing, transport, and use of produced oil and associated gas during the Reporting Period in which the oil and associated gas were produced, starting with the first Reporting Period.</p> <p>See the response to comments 5 for details on project eligibility for existing CO₂-EOR injection projects.</p>
	Climeworks	<p>What is the scientific rationale to foresee no incremental effect of EOR related emissions up to 2030 or 2028 (earliest)? E.g. the IPCC outlines the need for a rapid phase out of unabated fossil fuels in order to achieve temperature targets. We thus welcome the inclusion of such emissions as per the release of V2 of this standard.</p>	
	Oxy	<p>The methodology includes emissions from CO₂-EOR operations in the GHG accounting boundary after five years, which aligns with peer-reviewed literature on carbon accounting for CO₂-EOR.</p> <p>Note on EOR GHG: "The greenhouse gases included in calculations of baseline emissions and project emissions are shown in Figure 1 and Table 2 and their justification in Table 3. The emissions associated with</p>	

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		<p>the transportation, refining, and end use of hydrocarbons produced by EOR products (i.e., produced oil or gas) are included as project emissions five years after the project start date or January 1, 2030, whichever is first. Oil production through EOR would most likely displace an equivalent quantity of oil production with a higher carbon intensity." Question: Please define how this would affect currently existing CO₂ floods as it appears to be written for "greenfield" flood implementation. Oxy is open to discussion.</p>	
	Radicle	<p>Why does the accounting of these emissions start five years after project start date or after Jan 1 2030? What are you trying to accommodate by doing this? It feels like a work around and arbitrary. If remains, some context should be added as to the justification of this requirement.</p>	
48	ClimeCo	<p>"Oil production through EOR would offset an equivalent quantity of imported oil that is produced by primary production processes which do not involve CO₂ sequestration. Therefore, there are no incremental emissions associated with the combustion of the produced oil." – This statement is contradictory to what is stated previously in the protocol and the justification for including</p>	<p>The Methodology was updated to clarify that the oil produced via CO₂-EOR CCS projects operating under this methodology has a lower carbon footprint relative to other oil production due to the simultaneous injection and storage of non-geologic CO₂ that would otherwise be emitted to the atmosphere. However, since CO₂-EOR enables the production of fossil fuels</p>

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		<p>downstream emissions.</p> <p>There seems to be mixed message on EOR, both that it's displacing other high carbon intensity production so the combustion should not be factored (on page 21 footnote below the chart), and that the scope 3 emission should be counted (page 20, section 2.2, second sentence), then says after year 5 or Jan 2030. These seem counter to each other. It makes sense that geologic storage projects would generate more credits than an EOR project because of the subsequent climate impacts to that oil being combusted.</p>	<p>that will contribute to emissions, and because the projects must demonstrate a net benefit to the atmosphere, the methodology requires that the downstream emissions from the production and use of the oil and associated gas extracted via CO₂-EOR are included in the project accounting boundary. This robust accounting ensures that emission reductions credited under the Methodology are a clear demonstration of a net benefit to the atmosphere.</p> <p>See also the response to comment 96.</p>
49	ClimeCo	Table 3 – excluding CH ₄ and N ₂ O in project emissions is not conservative as stated. Remove from justification or clarify.	Table 3 from the public comment version of the Methodology refers to baseline emissions, not project emissions. Not including CH ₄ and N ₂ O in baseline emissions <i>is</i> conservative because it results in lower emission reductions and removals. Methane and N ₂ O <i>are</i> included in project GHG emissions.
50	ClimeCo	Regarding the 5-year monitoring post closure, I see there are requirements for insurance or a buffer pool for leakage, could this be a floating account or do the same credits need to be added on top each year for potential 10 to 50 years of operation? That could be a	The post-injection monitoring period is not part of a Reporting Period so no ERTs would be issued, and therefore no credits would need to be deposited into the ACR Reserve Account during this period.

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		huge pool.	
51	Carbon Engineering & 1PointFive	As with many innovative climate technologies, targeted government support is required to move along the cost curve and get to a place of broad commercial deployment. Around the world governments have targeted programs. We support the approach of ACR recognizing projects will need to receive government programs while still being eligible to generate credits.	<p>See the response to comment 2 for discussion of enrollment of a CCS projects in multiple GHG crediting programs.</p> <p>Section 3.1 (Regulatory Surplus Test) of the Methodology clarifies that tax incentives are allowed to be stacked with ERTs. The <i>ACR Standard</i> speaks to the permissibility of stacking GHG emission reductions and removals with crediting programs for other environmental and/or social attributes.</p>
	ClimeCo	It would be really helpful to clarify stacking of the ACR voluntary offset with other environmental attributes / government incentives such as RINS (RFS), LCFS, Cap-and-Trade in California and other states, 45Q, 45V. The goals of these programs are to decrease emissions, lower the carbon intensity of fuels, increase biofuel production, and overall support the energy transition to combat climate change; these are also the goals of the voluntary carbon market so they should all be pushing in the same direction – clarification on this topic is needed. For Cap-and-trade, it could almost be addressed in the 3.1.2 Retrofit Carbon Capture Systems paragraph two discussing a standards baseline or in the regulatory	

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		surplus test.	
	Milestone Carbon	<p>Request to clarify that offsets registered via ACR will be allowed to utilize 45Q tax credits and other credits from low carbon fuel standards, etc.</p> <p>Clarify that projects that receive tax credits, low carbon fuel credits, or any other value generating credits is eligible under the ACR methodology.</p>	
52	Climeworks	<p>We strongly believe in the importance of incorporating process emissions embodied in materials (sorbents/solvents). Both i) academic literature and ii) real world experience gathered via the operation of DAC projects, clearly point towards sorbent/solvent emissions as a key driver of overall emissions from DAC activities.</p> <p>The draft seems to assume emissions from sorbents/solvents used in the process to be de minimis or has ignored them for other reasons. For CDR activities such as DAC, academic literature is clear that emissions from solvents/sorbents for CDR activities can be a major emissions driver and should be included in the overall assessment. E.g. see: Terlouw et al. or Deutz/Bardow. According to above mentioned studies, emissions associated with the construction and disposal of CDR plants could be</p>	<p>Emissions associated with the production of sorbents and solvents used in CCS applications are de minimis and therefore not included in project emissions. Emissions associated with the use and regeneration of these materials <i>are</i> included in project emissions, as regeneration processes require electricity and/or thermal energy, which are within the GHG project boundary.</p>

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		<p>major as well, mainly depending on facility size. We welcome further information on either 1) why such construction emissions have been disregarded or 2) how to incorporate them in case significant.</p>	
53	Climeworks	<p>We welcome further guidance/clarity on the use of power purchase agreements and how they could be used to co-determine the EF of energy used in processes.</p>	<p>Appendix E was added to the Methodology. This appendix “prescribes the mandatory procedures for selecting, documenting, and applying emission factors and emissions-intensity metrics within all eligible CCS projects.” Emission factors are applicable to all project emissions, including combustion and electricity emissions.</p> <p>Appendix E includes guidance on acceptable electricity emission factors, including electricity emissions factors specific to the U.S. and Canada and allowing for the use of power purchase agreements.</p>
	Radicle	<p>The emission factor for electricity section seems to be out of place. It is not relevant to the equation 9 that precedes it. Suggest moving it to page 43 after EQ 11 where it is used.</p> <p>Suggestion is that there is a reference for EF elec for Canadian projects by province. From CFR or other regulatory programs.</p> <p>Recommend adding guidance for the EFs used in eq 15 and all fuel combustion quantification. What is acceptable? Should there be an EF handbook for all projects?</p> <p>The EFs referenced are for CH₄. It would be helpful to provide guidance on the EFs to be used for CO₂ service. The API compendium has guidance on adjusting the methane factors to CO₂. See section eq</p>	

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		6-1 and onward page 6-11	
54	Climeworks	On geographical coverage in V.: We encourage the standard to become applicable in different locations (e.g. in Europe) via subsequent versions of the protocol. Note that the European CCS Directive presents a viable backbone for activities in Europe.	Thank you for your comment about future versions of the CCS Methodology. At this time, the Methodology limits eligible countries to the United States and Canada.
	Drax	Include UK in the next iteration: Furthermore, we understand the need to keep the geographical scope contained, given the need for aligning the methodology with the underlying regulations. We would however suggest you include the UK in the next iteration of the methodology, due to the leading regulatory framework in place, its early start in off-shore storage, and committed capture players, such as Drax, ready to implement several MT worth of removals each year.	
	Radicle	Consider expanding the geographic coverage for DAC and BECCS to worldwide, or at least inclusive of EU, UK. High quality removal credits are/will be in great demand more supply of this type of credit should be encouraged. On the other hand, California LCFS	

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		<p>allows DAC worldwide and no need for fuels to be sold in California so projects will likely participate in that market rather than in the voluntary market, unless the requirements in the voluntary markets are less cumbersome.</p> <p>You could allow for expanded geographies for CCS by making requirements to prove that the jurisdiction has adequate regulatory framework in place. Set some minimum criteria.</p> <p>Add a requirement only projects in Jurisdictions that have established framework for MMV plan requirements and long term containment liability can register projects. ACR will do a regulatory review and provide ruling on what jurisdictions (national and subnational) meet a minimum acceptable standard.</p>	
55	Climeworks	We welcome future guidance as regards compatibility with the pending Article 6 frameworks of the Paris Agreement.	ACR designed the CCS Methodology to be consistent with the framework established under Article 6.4 of the Paris Agreement, including but not limited to the requirement for baselines to be below business-as-usual.
56	Climeworks	We welcome the performance based assessment of post-injection monitoring obligations.	Thank you for your support.
	Climeworks	Climeworks welcomes a simplified approach to	The calculation framework was developed to

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57		<p>determine vented and fugitive for CDR projects. I.e.: Since all the CO₂ is originally captured from the atmosphere, vented and fugitive emissions will be incorporated in the calculation as long as the last monitoring point (i.e. monitoring inside the injection well/wellhead) can be used to inform the total amount of emissions captured. This helps simplify projects where a single step DAC (+transport) + Storage defines the setup. Instead of measuring at every individual step, one final measurement serves the same goal.</p>	<p>accommodate a wide range of project types. For instance, a straightforward DAC project may require only simple calculations, whereas more complex projects, potentially involving multiple CO₂ sources (including DAC), long-distance transportation with compression, injection into multiple reservoirs, etc., would require allocation of emissions across different segments. Accurate measurement and accounting of project emissions across all project segments are essential to ensure transparency, traceability, and confidence in the integrity of reported reductions and removals.</p>
	Phillips 66 Company	<p>Table 7 contains monitoring requirements for key parameters needed to calculate the baseline and project emissions described throughout the document. In some cases, parameters are required to be directly measured even though they may be calculable via mass balance methods. For example, if the feed flow rate and hydrocarbon composition to a combustion process is known, the total amount of carbon entering the combustion process is known. In the downstream post-combustion capture process, a captured CO₂ stream and a non-captured CO₂ stream is produced. Measurement of only one of these two streams is required to be able to quantify both. Table 7 and its supporting language should provide flexibility for the calculation of parameters through</p>	

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		unit mass and energy balances where sufficient.	
58	Drax	Include BECCS in the next iteration of the methodology: Our reading of the methodology is that it does not cover the production of negative emissions from BECCS. We would welcome clarity on that point, and strongly encourage ACR to ensure its methodology deals with BECCS negative emissions, since DAC and BECCS are the two engineered removal technologies that have most potential to provide negative emissions at scale.	The Methodology was updated to clarify that BECCS and BiCRS projects are eligible for removals under this version of the methodology, but only if they utilize sustainable biomass as defined in Appendix D.
59	Drax	Set stringent criteria for the use of biomass: While we appreciate the requirement to only use slash and waste, we would argue that today’s credible BECCS players, including Drax, take measures which are significantly more specific to ensure environmental integrity and avoidance of leakage. We believe any methodology should only allow for BECCS which has a low risk of negative leakage, and ideally, encourages positive leakage (ie greater than 1 tonne of carbon mitigated per tonne of carbon captured and stored), considering both land and energy system impacts. This relies on ensuring only sustainable sources of biomass are used in BECCS which meet safeguards set by standard setters such as Sustainable Biomass Programme (SBP), the Sustainable Forest Initiative	The Methodology was updated to enable and clearly define sustainable biomass in Appendix D. The Methodology’s criteria for sustainable biomass serve to prevent the use of any biomass feedstock that could result in an increase in GHG emissions. These requirements also serve as an environmental and social safeguard to ensure that biomass sourcing and use do not cause adverse impacts such as deforestation, land-use change, or degradation of ecosystem services. Any CCS project using biomass must use sustainable biomass as defined there.

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		(SFI), Forest Stewardship Council (FSC) and the Programme for the Endorsement of Forest Certification (PEFC).	
	Summit Carbon Solutions	Sustainable Biomass is defined on page 7 and included in section 1.2, footnote 3 on page 14. This definition is not consistent with regulatory definitions in the US and Canada. Specific to the US, the Renewable Fuel Standard (RFS2) defines Renewable Biomass, which is required for compliance in biofuels production. Other sections of the methodology, such as the storage requirements, leverage regulatory requirements like class VI well permits in the US. Summit Carbon Solutions recommends the methodology leverage regulatory definitions and compliance programs for Renewable and Sustainable Biomass as well. The specific definition in RFS2 can be found in section II.B.4. in the following link to the regulations: https://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf	
60	Milestone Carbon	Add definition for ERT, RMC, and VVB to Acronyms and Definitions section.	Acronyms and abbreviations are defined in the “Acronyms & Abbreviations” section of the Methodology as well as in the <i>ACR Standard</i> .
	Shell	The term ERT is not defined in the methodology.	

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61	Drax	<p>Integration with ETS / Cap and Trade: In countries with ETS systems in place and CO₂ leaks included in these, there should be no necessity for any other recompense to be made in the voluntary carbon market in the event of a future leak from a storage site, since this would be double mitigation. As these overall ETS markets are capped, if a storage owner is required to purchase ETS allowances in the event of a leak, this will result in emissions being reduced elsewhere, because the volume cap on the ETS scheme will control the total number of emissions. This should be sufficient safeguard for a purchasers of carbon credits, knowing that in the event of a future leak, action will be taken by the storage owner / operator, that will ensure that the effect of the carbon credits purchased remains the same (the leak has been compensated for by emissions being reduced elsewhere, which will have been paid for by the storage owner / operator).</p>	<p>If a project is under the jurisdiction of a GHG cap-and-trade system or other emissions trading system (ETS), and that system requires it to account for emissions from a geologic storage reservoir, those emissions would presumably have already been accounted for as reductions within the same program. This would be a situation of double counting that is disallowed by the <i>ACR Standard</i>.</p> <p>Even if the stored CO₂ had not already been accounted for, the CCS Methodology’s GHG assessment boundary does not include the collective emissions limits of a cap-and-trade system or ETS; therefore, system-related allowances do not factor into CCS Methodology accounting.</p>

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62	Milestone Carbon	Add Natural Gas Processing (or refining) to address acid gas removal and natural gas liquefaction facilities, respectively. Notwithstanding the list of eligible project activities not being exhaustive, the number of potential sites is greater than some of the activities listed (e.g. vs. cement production), and the absence of this category may imply a higher burden to meet eligibility.	Examples of industrial processes that are eligible CO ₂ sources (as outlined in Table 1 of the Methodology) are listed in Tables 2 and 3, which explicitly include natural gas processing and oil refining. Petrochemical production would also be considered an industrial source.
	Ozona	We assume emissions from Refining and Petrochemical assets would be covered under “industrial processes.” Industrial Processes like Cement, Steel, Hydrogen, and Electrical Power are mentioned by name – Refining and Petchem is not. We at Ozona are working to capture pre- and post-combustion sources from Refining and Petrochemical assets. If it is to give the appearance that the registry does not support prolonging the life of fossil fuels, we understand. We just need to know we are covered.	
63	Milestone Carbon	The period to apply to renew the Crediting Period should begin prior to expiry of the current Crediting Period. As drafted, there will be a period following the expired Crediting Period where CO ₂ is being reduced or removed and no offsets are being generated.	Crediting Period renewal requirements are outlined in the <i>ACR Standard</i> and the renewal process enables a seamless transition between Crediting Periods.

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64	Milestone Carbon	All CO ₂ injection wells in the US should meet requirements outlined by USEPA UIC program. CO ₂ injection wells can be permitted as Class II and meet requirements of USEPA UIC program, so they should not only be required to meet Class VI requirements.	Thank you for your support.
65	Milestone Carbon	For matters of 3rd party verification, recommend including a Dispute Resolution process, which may include the Parties selecting an outside expert to decide the matter.	A process for registering complaints, including those involving ACR-approved VVBs, is outlined in the <i>ACR Standard</i> .
66	Milestone Carbon	The requirements for proof of financial responsibility should not be left to judgment and should not be limited to private insurance or an ERT Reserve Account. There are several ways to demonstrate sufficient financial strength to cover operations or potential liabilities.	The Methodology was updated significantly to clarify permanence requirements. This includes a requirement that projects must demonstrate compliance with financial responsibility requirements under applicable laws and permits (e.g., UIC). See also the response to comments 23.
67	Milestone Carbon	C.2 - Consider removing as Class II wells can be “non-commercial” under the current definition. C.2.1 - Class II well permits are evaluated and processed by the Injection Storage Permits Division (within the Technical Permitting Section). C.2.1 - Remove sentence regarding “hearing...requested or required” and replace with	Appendix C (Standards and Procedures for Class II Well in Texas) and Appendix D (State Legislative Actions) were removed due to rapid development of laws and regulations across the U.S. and Canada that could not be accurately reflected in an appendix.

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		<p>the following: “Applications are evaluated for administrative completeness as well as technical completeness. Should a protest or ruling (not in the applicants’ favor) exist, there would be an opportunity to request a hearing. Hearings would be scheduled by the Hearings Division. The Hearings Division would notify all affected party members to coordinate a date that is agreeable.”</p> <p>C.2.1 - replace “examiners” with Administrative Law Judge and Technical Examiners</p>	
	Oxy	<p>General Comment: This section includes for an overview of Class II UIC wells in Texas but not an appendix for Class VI wells at the federal level nor the other states with primacy. Recommendation: Provide an overview of the federal Class VI requirements and major phases. For example sections 1.2 and 1.3 from the following EPA UIC Class VI Implementation Manual [https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf].</p>	
68	Oxy	<p>Oxy supports the inclusion of Class VI injection wells and the integration of existing state and federal regulations into the Methodology’s storage</p>	<p>Thank you for your support.</p>

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		requirements. This minimizes additional reporting burdens while ensuring alignment with regulatory frameworks. Suggested Revision: Maintain and strengthen the integration of Class VI injection wells and ensure continued alignment with state and federal regulations to facilitate project implementation.	
69	Oxy	<p>Portion VIII - "Demonstrate surface use agreements for the duration of the project term to conduct post-injection monitoring and, if necessary, remediation." Question: Does this apply to the minimum 5-year post injection monitoring period stated in section 5.3.1.4? What is the timing expectation for the associated requirements for surface use agreements/site monitoring access? Recommendation: Match the surface use agreement/site monitoring access it the minimum 5-year post injection monitoring period or such time that it is proven that safe and secure storage of the CO₂ has been achieved.</p>	The post-injection monitoring period is a minimum of five years but extends beyond that in two-year increments until plume stabilization is demonstrated. The Methodology was updated to clarify that the Project Proponent, VVBs, and ACR must have access to the site throughout the Minimum Project Term, including the post-injection monitoring period.
70	Oxy	<p>"The minimum post-injection monitoring period for CCS projects is five (5) years." o General Comment: Class VI wells have a default post injection monitoring period of 50 years; however, the class VI requirements also have the option to reduce this period if the Project Proponent can show that</p>	Thank you for your support.

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		<p>safe and secure storage of the CO₂ has been achieved.</p> <ul style="list-style-type: none"> o Specific Comment: Oxy believes this to be a reasonable post injection monitoring period. However, for our existing CO₂-EOR projects under the Class II UIC programs in Denver City, Hobbs, and West Seminole our internal experts estimated two to three years to be sufficient to show safe and secure storage. o Recommendation: Retain the recommended 5-year post-injection monitoring period. Point of clarification – this minimum post-injection monitoring period does not relieve the storage operator of their responsibilities under the UIC program but is simply the minimum amount of time ACR has recommended would be allowed by the registry for the demonstration of safe and secure geologic storage as defined under the Class VI/Class II rules. 	
71	Oxy	<p>Oxy supports the concept of carbon-neutral oil and has provided a literature review demonstrating its technical feasibility. The methodology should recognize this potential and ensure proper lifecycle emissions accounting for CO₂-EOR. Suggested Revisions: Establish clear lifecycle carbon accounting criteria for carbon-neutral oil derived from CO₂-EOR and DAC, aligning with global best practices and emerging industry standards. Continue to refine CO₂-EOR emissions accounting to ensure robust and</p>	<p>The Methodology’s GHG assessment boundary for oil produced via CO₂-EOR is drawn widely and includes the emissions associated with oil production, processing and refining, transport, and end use. This wide boundary is employed since CO₂-EOR enables the production of fossil fuels that will contribute to emissions and because the projects must demonstrate a net benefit to the atmosphere. This approach ensures that the changes in GHG emissions due</p>

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		transparent methodologies for quantifying removals and applying them to commodities such as carbon-neutral oil.	to the production of the oil are accounted for within the Methodology. Per the <i>ACR Standard</i> , ACR only issues carbon credits on a metric ton CO ₂ e basis, not on carbon intensity (as is used for fuels).
72	Oxy	<p>Key statement of CO₂ movement within EOR network - "While not technically an emission, CO₂ transferred outside the project boundary (i.e., produced CO₂ from an EOR operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an EOR site operator intends to move produced-CO₂ between fields, then the boundary would encompass the multiple fields employed (making sure to account for emissions from all relevant stationary combustion, vented, and fugitive emissions sources)."</p> <p>Question: How does ACR envision this working in Practice? Would the operator need to estimate the associated field emissions for the original field along with production volumes from both fields after the proposed 5 year grace period? Additional clarity and a potential worked example on this would be appreciated. Oxy would be interested in a</p>	<p>If a Project Proponent elects to transfer captured CO₂ to another field that is within the project boundary (i.e., using that CO₂ for EOR as part of the CCS project), that CO₂ would not be considered an emission. However, if the CO₂ were transferred outside the project boundary (i.e., for injection into a field not included in the project or for another use), that transfer of CO₂ would be considered an emission. Note that the five-year delay in accounting for the project emissions from refining and processing, transport, and use of produced hydrocarbons was removed from the Methodology.</p>

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		collaborative effort with ACR on this topic.	
73	Oxy	<p>The methodology should clarify its approach to shared CCUS infrastructure, such as pipelines and storage hubs, and how leakage and emissions should be allocated among multiple projects using shared assets. Suggested Revision: Define a standardized approach for handling shared CCUS infrastructure and leakage allocation mechanisms, ensuring fair and consistent carbon accounting.</p> <p>The methodology lacks specific guidance on how to allocate CO₂ losses from transportation and storage infrastructure, especially in the context of shared CCUS projects. Suggested Revision: Establish a transparent mechanism for CO₂ leakage accounting and allocation within shared infrastructure, ensuring accurate and fair emissions tracking across project participants.</p>	<p>This Methodology’s general approach to project design and quantification is for a single Project Proponent rather than for multiple independent project developers; however, this structure does not preclude a Project Proponent from contracting with, partnering with, or otherwise coordinating activities across multiple parties or infrastructure owners within a CCS project, provided that the Project Proponent retains responsibility for compliance with all Methodology requirements.</p> <p>The Methodology includes provisions for accounting for emissions from pipelines used by multiple users.</p>
74	Oxy	<p>Step A "Production GHG" – There does not appear to be an input for nor recommended practice for a method by which to allocate emissions for natural gas processing emissions over the life of the CO₂ flood (e.g. NG sales and full NGL extraction also occur within a CO₂-EOR processing plant. These</p>	<p>The Methodology was updated to expand the accounting of GHG emissions beyond oil production to include all oil and associated gas production, refining and processing, transport, and end-use.</p>

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		hydrocarbon products are generally kept separate from the oil production associated with the gas handling, dehydration, CO ₂ re-injection and compression). Step D “Refining” – There does not appear to be an input for the refining of the associated NGL products from the CO ₂ -EOR processing plants here either	
75	Oxy	The methodology does not clearly define the GHG accounting boundary for CO ₂ -EOR projects, particularly in differentiating natural-dome CO ₂ from anthropogenic or atmospheric CO ₂ sources. Suggested Revision: Develop clear guidelines for distinguishing baseline emissions in mature CO ₂ -EOR operations and provide guidance on amending the GHG accounting boundary after the five-year grace period expires.	Natural-dome CO ₂ is explicitly excluded from eligibility under this Methodology, and the Methodology was updated to more clearly define CO ₂ source baseline accounting. Note that the five-year period was removed from the Methodology.
76	Ozona	The methodology reviewed was solid. Good work.	Thank you for your support.
77	Phillips 66 Company	All measurements that do not require laboratory analysis or accounting reconciliations (e.g. % CO ₂ Sold), will likely be coming from field instrumentation. Current instrumentation technology should allow standardization of measurement frequency to “Continuous” with Monthly Average reported for verification. Standardizing on continuous	The Methodology was updated to clarify what parameters must be measured continuously versus at other frequencies (see Table 7).

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		<p>process monitoring with field instruments and Internet of Things (IoT) devices as much as possible would result in strengthening of CCS-generated offset quality compared to nature based and other difficult to verify projects. In our view, the technology is mature and already being implemented at process facilities. This is an opportunity to truly differentiate the quality of CCS based offsets and we encourage ACR to incorporate standardization of measurement frequency by fully utilizing currently available technology.</p>	
78	Phillips 66 Company	<p>For offset title, Project Developers will benefit if ACR addressed not just the transfer of title between capture, transport and sequestration entities but also the Sale and Purchase of Offsets to and from 3rd parties, which is a core use case for the methodology. In this scenario, it would be good to have some explicit recommendation on documentation and reporting of sold and/or purchased offsets with respect to seller’s and buyers’ Scope 1 emissions. Although this is not germane to the verification process, being more explicit on this topic could help standardize and build confidence in the reporting obligations in Sale and Purchase contracts that get executed.</p>	<p>This suggestion is outside the scope of the CCS Methodology. The ACR provides reports on the retirement of carbon credits along with the retirement purpose and associated environmental claims per the Registry Operating Procedures. Credit transfers between parties (e.g., sale and purchase) are recorded but not made public.</p>

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79	Phillips 66 Company	We appreciate the flexibility provided by the protocol to Project Developers in managing the risk of CO ₂ reversals via either purchase of private insurance or creation of an ERT Reserve Account.	Thank you for your support. Please note that the Methodology requires a CCS Project Reversal Risk Mitigation Contract between ACR and the Project Proponent in addition to contributions to the ACR Reserve Account—or another ACR-approved risk mitigation mechanism.
80	Phillips 66 Company	We appreciate inclusion of offshore reservoirs for CO ₂ storage in the ACR CCS protocol. In addition, we appreciate the protocol’s intentions and provided recommendations to follow the EPA Underground Injection Control (UIC) protocol for Class VI wells and State regulations regarding pore space and liability. Alignment with existing federal and state regulations will facilitate efficient development of CCS projects without additional burden of following separate requirements.	Thank you for your support. Please note that the Methodology was updated to limit offshore geologic storage reservoirs to those in the jurisdictional waters (i.e. the Exclusive Economic Zone) of the United States and Canada.
81	Radicle	Consider expanding the Sustainable biomass definition to include slaughterhouse waste	If slaughterhouse waste meets the certification and other requirements in Appendix D, it can qualify as sustainable biomass. Note that the biomass must be used as a fuel or feedstock in an eligible CO ₂ source, though.

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82	Radicle	The phrase “additional projects may be determined to be eligible through consultation with ACR” leaves a very wide opening for discussions of other project types. Allowing for Flexibility Mechanisms and appropriate deviations request are welcomed, but suggest some boundaries and guidance is made explicit to ensure consistent treatment of requests for flexibility or deviation.	This language was removed from the Methodology. The list in Table 1 is inclusive of all eligible CO ₂ sources, methods of transport, and storage reservoirs.
83	Radicle	Applicability conditions. It is unclear if projects must meet all criteria I through VIII or only the ones relevant to their project. i.e VI “EOR projects with CCS” – hasn’t that been addressed as applicable in table 1, why repeat? Suggest removing condition VI.	Section 2 was updated to clarify that "project activities must satisfy all of the following eligibility conditions" listed.
84	Radicle	“CCS Projects that are constructed” Clarify activities associated with CCS definition does it include sequestration and EOR projects or do you mean just those going into depleted reservoirs or saline aquifers. The definition on p 5 could be made more explicit to indicate the use of CCS covers all geological sequestration and EOR activities if that is what is intended	The Methodology was updated to remove the noted language from the “Start Date” section. Section 2 of the Methodology clearly outlines what CCS project activities are eligible.
85	Radicle	SSR 4 labeled as produced Hydrocarbons description is incomplete and lacks clarity. Is this meant to be the hydrocarbons produced during EOR operations? It is	Figure 3 and Table 5 were updated to clarify which emissions are within the GHG project boundary for produced oil and associated gas

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		<p>unclear why the description is limited to emissions during plugging operations. Check to confirm the SSR label and description are aligned with your intention – Was it meant to account for decommissioning in the project condition?</p>	<p>(for CO₂-EOR projects only). The emissions associated with decommissioning and closure are also included in project emissions.</p>
	<p>Shell</p>	<p>It is not clear why Category 4 SSR “Produced hydrocarbons” is described as “Emissions from mobile mechanical equipment for plugging.” Perhaps Category 4 is intended to be emissions from site closure and well plugging and abandonment. However, these are emissions that would occur after injection has ceased. Just as well drilling emissions are excluded, it seems well plugging/abandonment emissions should be excluded.</p> <p>“Produced gas (from EOR)” is confusing. It would be more clear to describe this as “CO₂ used for EOR transferred outside project boundary” to distinguish it from any hydrocarbon gases produced during EOR operations.</p>	
<p>86</p>	<p>Radicle</p>	<p>Suggest that the baseline emissions be CO₂ injected and measured as close to the wellhead as possible as in Alberta Quantification Protocol for CO₂ Capture and Permanent Storage in Deep Saline Aquifers or Quantification Protocol for Enhanced Oil Recovery -</p>	<p>Using injected CO₂ as equivalent to baseline emissions for the primary CO₂ source assumes that no CO₂ from a secondary CO₂ source (see the Methodology for a definition of this term) is being stored and that there is a direct, non-</p>

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		<p>not what would otherwise have been emitted from the entire facility. This removes the complexity of adjusting facility emissions for the operation of capture equipment (AF) in Eq 1 p33</p>	<p>comingled pipeline of CO₂ between the primary CO₂ source and the geologic storage reservoir. Further, it assumes that there is no increase in emissions from the operation of primary CO₂ source. These conditions will not occur in every project.</p> <p>The Methodology’s equations allow for the use of injected CO₂ as modified by other measured values for baseline emissions, but this must be compared to another calculation (using CO₂ captured from the primary CO₂ source, modified by the adjustment factor) and the lesser of the two values used for baseline emissions. This approach allows for flexibility for different project configurations and ensures conservatism in baseline emissions.</p>
87	Radicle	<p>Why exclude CH₄ and N₂O from GHGs due to capture? For completeness, include since a source could be from fuel combustion.</p>	<p>All CCS projects must quantify project-related CO₂, CH₄, and N₂O emissions. Methane and N₂O emissions are only excluded from accounting for baseline emissions from the primary CO₂ source, as this is conservative.</p>

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88	Radicle	<p>Relevance/Completeness: Potentially sources to be included in the project condition are material inputs to capture operations (i.e amine), EOR drilling and well service emissions, and recycle/disposal of materials used in capture operations.</p>	<p>The Methodology was updated to include project emissions from construction (including well drilling, if new wells are drilled for the project) and decommissioning, including onsite emissions like fuel combustion from construction machinery, construction-related transport emissions, and the production of building materials with high emissions intensity—namely, cement, asphalt, and steel. The emissions associated with transport of materials during decommissioning to other sites (e.g., disposal or recycling site, new project facility) are also included. For more details, see Sections 6.2.4 (Construction Emissions) and 6.2.5 (Post-Injection Period Monitoring, Decommissioning & Closure Emissions) of the Methodology.</p> <p>Related to well servicing, Equation 20 states that combustion and electricity-related emissions include the emissions from “equipment used to maintain and operate the CO₂ handling and injection wells, CO₂ recycling devices, and production wells.”</p> <p>See the response to comment 52 for a discussion of capture media like amines.</p>

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89	Radicle	<p>Allowing a standards-based baseline introduces unnecessary inaccuracies. What if there is no regulation to provide the standard? In SK would you use the Performance allocation benchmark as the performance standard? Projection based is preferable especially if measured at the point of injection. In that proposed case, Net reductions are CO₂ injected less all-project condition GHGs. This is best practice under 3 existing Protocol - CCS Protocol Under the Low Carbon Fuel Standard and both Alberta CCS and Enhanced Oil Recovery.</p>	<p>The Methodology was updated to clarify that the intensity-based baseline (name updated from “standards-based baseline emissions”) approach is only used when there is a legally mandated GHG emissions intensity standard for the CO₂ source.</p> <p>In jurisdictions where there is an emissions <i>reduction</i> benchmark (as opposed to an <i>emissions</i> intensity standard), only emission reductions that go beyond the legal requirement are eligible for crediting. Emission reductions from CCS accounted for under any other program (including but not limited to Saskatchewan’s Output-Based Performance Standards Program), and any emission reductions beyond a CO₂ source’s requirement that are traded to another entity, are not eligible under ACR’s CCS Methodology. Projects in Saskatchewan with primary CO₂ sources subject to an output-based performance standard may need to consult with ACR.</p> <p>See the response to comment 86 for why use of CO₂ injected is not an accurate measure of baseline emissions for many projects.</p>

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90	Radicle	BE performance standard, as prescribed by regulation. Requiring actual measurement improves relevance, completeness, accuracy.	The intensity-based baseline emissions (name updated from “standards-based baseline emissions”) approach requires the measurement of the output of the primary CO ₂ source.
91	CarbonVert	I’m unclear what this [Section 4.2.4] is supposed to be. It seems to be two separate things joined into one. Equipment leakage/failures and credit claw backs. A more efficient approach would be to say that credits are only valid when the appropriate regulatory permit is in compliance.	The Methodology was updated to more clearly differentiate among GHG sources, sinks, and reservoirs. Section 6 (Quantification of GHG Emission Reductions and Removals) and the equations therein were also extensively updated to distinguish between baseline and project emissions and to better explain meter location requirements; this section of the Methodology replaces Section 4.2 of the public comment draft. Section 6.1 and the Definitions section distinguish between primary CO ₂ sources (formerly called “primary processes”) and secondary CO ₂ sources, and more clearly defines how the emissions from these sources must be quantified. ACR agrees that projects are only eligible when they are in regulatory compliance. The <i>ACR Standard</i> , which all projects must conform to, states that projects must demonstrate
	Climeworks	Footnote 7: We applaud the inclusion of CH ₄ emissions if those emissions are above de minimis levels (>0.5% of total facility wide GHG emissions) and welcome further detail on the calculation of total facility wide GHG emissions, e.g. is it also encompassing upstream emissions and in what consistency have facility wide GHG emissions to be treated, noting that projects may restrict the boundaries of assessments to the parts of the processes relevant for this methodology (e.g. the H2 example stated earlier in the document). In that sense, we also favor an inclusion of CH ₄ emissions as a potential emission source within the 2) Capture	

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		<p>emissions.</p> <p>Clarification request: "Any GHG emissions from the capture process or energy generation shall be subtracted from the total CO₂ credited." Does this include emission sources that haven't been stated earlier in section 2.2? E.g. see [comment 52] above.</p>	<p>"compliance with all relevant local, national, and international laws, regulations, conventions and agreements."</p> <p>All CCS projects must quantify project-related CO₂, CH₄, and N₂O emissions. Methane and N₂O emissions are only excluded from accounting for baseline emissions from the primary CO₂ source, as this is conservative.</p>
	Radicle	<p>CO₂ produced must be measured downstream of capture facility if it is to include venting and fugitives etc. due to capture. Suggest add clarity on the metering locations with a sample schematic.</p> <p>Footnote 24 where alternate quantification is shown for the case when one stream measurements is not possible seems to be more likely than Eq 6 which is based on a total volume of CO₂ being measurable. Eq 6 seems like an oversimplification in most cases. Examples and schematics can add clarity. Consider adding them in an appendix.</p> <p>SSR 1 is labeled as facility emissions and the description says primary process emissions and then goes on to say that CO₂ in the baseline is "included". This is misleading to some extent since not all CO₂ facility emissions are included, I believe only those that are fed to the capture facility are included. For example, any flared and vented emission upstream of the capture which are facility emissions are not</p>	

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		<p>considered in the volume of CO₂ gas produced from primary processes, nor are combustion emissions from individual point sources like stationary combustion, stacks. Maybe just label SSR as Facility and not Facility emissions.</p> <p>Clarify - Primary Process – too vague. Does this include individual stationary combustion emissions which are not captured but are a part of the process?</p>	
	Shell	<p>The term “project’s actual CO₂ capture facility” is not understood in the context of setting a projection-based baseline.</p> <p>Clarification is needed on language used in the table. Under “Baseline,” why is the reference to gas stream “captured” from the primary process? Would not the baseline be the CO₂ emissions from the primary process?</p>	
	Summit Carbon Solutions	<p>The methodology requires the quantification of all CO₂ produced from the primary process and that this must be done through meters included directly downstream of the primary process. This requirement does not impact the quantification of ERTs from the methodology and requires meaningful additional burden to Project Proponents for compliance (cost of meters for installation and</p>	

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		ongoing operations and maintenance). The methodology should consider removing this requirement or providing other options for estimating the CO ₂ produced from the primary process. For example, ethanol production releases CO ₂ at a known rate per gallon produced. Primary process CO ₂ emissions can be accurately estimated based on volume of ethanol produced in place of a downstream meter.	
92	Radicle	Define dedicated pipeline. Are you saying that the pipeline must contain only CO ₂ that has been captured from industrial sources? Is a pipeline that comingles naturally occurring CO ₂ eligible? https://www.eoriwyoming.org/projects/recent-projects/236-us-CO₂-eor-survey-update-2021 . Total CO ₂ Supply: 1.6 Bcf/d ; “Natural” CO ₂ : 1.3 Bcf/d ; “Industrial” CO ₂ : 0.3 Bcf/d Recommend including specifics about proration in these cases.	The Methodology was updated to remove the term “dedicated pipeline” and to clarify that “CO ₂ sourced from natural carbon dioxide-bearing formations” is ineligible under the Methodology. Carbon dioxide from natural CO ₂ -bearing formations must be excluded from baseline emissions; however, when CO ₂ from natural CO ₂ -bearing formations is used for CO ₂ -EOR, any emissions associated with venting of this CO ₂ must be included in project emissions.
93	Radicle	The mass balance approach to quantify vented and fugitive emissions from transport may present complexities for transportation networks with multiple capture and multiple injection locations. Careful consideration must be taken with a proration factor assigned for allocation.	The Methodology was updated extensively to only utilize a mass balance approach for transport venting emissions when project CO ₂ is <i>not</i> comingled with non-project CO ₂ . Mobile transport would apply to individual containers; as such, volumes must be measured at the

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		<p>Also if “natural” CO₂ and Industrial CO₂ are comingled in the pipe another layer of complexity is added. Is there any logical default that could be applied to make a conservative estimate? Suggest developing an emission factor based on km traveled, or component count and EF for fugitives in all cases, not only for those with an uncertainty analysis.</p> <p>If moving away from a mass balance approach, the vents should include intentional and unintended vents.</p> <p>For transportation by truck/vehicle, the meters must also be carefully considered to ensure that the vents from loading/unloading are accounted for. Calibration of the meters and scales are critical. For some of the early EOR projects in Alberta, this measurement was particularly challenging and a large source of loss. Section 4.2.3 addresses the complexity, but consider providing more prescriptive approach for system wide factors.</p>	<p>input to the mobile transport mode and upon delivery to the injection and storage site to account for vented emissions. If mobile transport containers contain eligible and ineligible CO₂, the relative amounts of CO₂ (1) at input to the mobile transport mode and (2) at delivery to the injection and storage site must be measured and vented emissions (value (1) – value (2)) applied on a proportion basis (project CO₂ input into transport mode / total CO₂ input into transport mode * vented emissions).</p> <p>See the response to comment 92 for discussion of comingled CO₂.</p> <p>Measurement requirements, including requirements for calibration, are now clearly stated in Section 7.2 (Measurement Requirements).</p>
94	Radicle	<p>Produced CO₂ transferred offsite may not be only applicable to EOR. Consider the case where CO₂ stored is eventually used for other uses as a feedstock to other products. This term should be left to designate CO₂ transferred offsite for any reason – consider it an intended reversal.</p>	<p>The Methodology was updated to clarify (in Equation 7) that any CO₂ transferred outside the project boundary is considered an emission and must be accounted for in project emissions.</p>

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95	Radicle	<p>How should Appendix A be used for EOR projects in Canada? The information is US centric. Also, this is crude specific, what [sic] the potentially produced methane/other HC streams?</p> <p>Omission observed - No Canadian references supplied [in Appendix A ,Tables 11,12, and14].</p>	<p>The Methodology was updated extensively to include associated gas-related emissions and to clarify that Appendix B (Produced Oil Emission Factors (U.S.); formerly known as Appendix A) is only applicable to U.S. projects. Section 6.2.6 (Produced Oil & Associated Gas Emissions (CO₂-EOR Only) of the Methodology was updated to clarify that projects in Canada should use either the Canada-specific emission factors listed in Table 19 or the R&D GREET model.</p>
96	Radicle	<p>The Alberta Enhance Oil Recovery Protocol excludes emission from the produced hydrocarbons Eq 29. From the AB protocol: “The baseline scenario for this activity is non CO₂-enhanced oil recovery and emitted CO₂ from a large emitter. The operation during the baseline is assumed to be enhanced oil recovery, without the use of CO₂. Thus, the oil produced from a CO₂-EOR project can be assumed to be unchanged. The oil production is not an additional activity and does not factor into the calculation of sequestered CO₂. The emissions associated with oil production are considered equivalent in the baseline and the project condition so are excluded from the protocol. The baseline for this protocol is dynamic projection-based. Therefore, during the project, the total</p>	<p>The Methodology conservatively assumes that no oil production occurs in the baseline scenario. This approach is appropriate because it aligns with Article 6.4 of the Paris Agreement requirements for baseline below business as usual and counters assertions that the Methodology encourages the production of additional oil.</p> <p>The quoted text at the bottom of p. 21 in the public comment version of CCS Methodology v2.0 was a continuation of the text from footnote 8 on p. 20. This text was removed from the final version of the Methodology.</p>

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		<p>quantity of CO₂ measured directly upstream of the injection wellheads is projected to the baseline condition. This does not include the quantity of any reinjected CO₂ (i.e. recycled CO₂) or previously credited CO₂.”</p> <p>Recommend adopting the same justification and excluding emissions from produced hydrocarbons (Eq.29) from this protocol. There is not incrementally more fuel coming to market because of this activity. The same fuel is coming to market, it is merely being produced differently. If you cannot assume the same position as Alberta, consider comparing to other traditional crude oil production technologies and emissions that would be used to produce the same fuels, but exclude refining and end use as equivalent project to baseline and consider excluding transportation baseline condition to project condition as immaterial.</p> <p>Is this text meant to be a footnote, if yes it has no number Is [sic] attached. It seem [sic] to be orphaned: “oil production through EOR would offset an equivalent quantity of imported oil that is produced by primary production processes which do not involve CO₂ sequestration. Therefore, there are no incremental emissions associated with the combustion of the produced oil.” Also, these words</p>	

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		<p>seem contradictory since emissions from produced hydrocarbons are included in SSR4 (Eq 29) PE end use is combustion.</p> <p>(Completeness) - If PE production emissions are included in the project condition emissions, then suggest there should be a BE production emission included in the baseline condition. The hydrocarbons from EOR will be displacing HCs that would have been otherwise produced by BAU (baseline) HC production. If you include this in the project condition you must include and SSR in the baseline condition for what would have been otherwise produced. This approach assumes that new HC Supply is not created, but rather that BAU HC is displaced. Notionally demand remains the same. Along those lines, a case could be made to exclude in both the project and the baseline as equivalent or conservative to exclude.</p>	
97	Radicle	<p>The post injection monitoring period seems very short (5 years), if no leaks and a stable plume. If can't prove this then, requirement to monitor will be extended in 2-year increments. Recommend adding context for who is the decision-making body overseeing the MMV and ensuring requirements have been met. Regulators?</p>	<p>The Methodology was updated to state that the end of the post-injection period only occurs after a minimum of five years and when the condition of plume stability being met. This approach is more rigorous than approaches that are only specific to timeline because it ensures that the condition which is most indicative of emissions reduction and removal</p>

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			<p>permanence is achieved. After the conclusion of the Crediting Period, other risk mitigation measures and compensation procedures (contained in a legally binding ACR CCS Project Reversal Risk Mitigation Contract) still apply to the injected CO₂ to ensure the integrity of the carbon credits issued during the Crediting Period.</p> <p>The Methodology was also updated in Section 7.3 to state that the MRV Plan must be reviewed and approved by a jurisdictional authority (consistent with other requirements in Section 7.3.1) or, if no jurisdictional authority exists, by the VVB’s qualified professional expert in CCS.. This qualified professional expert is also responsible for verifying plume stabilization.</p>
98	Carbonvert	Is the independent assessment completed for receiving 45Q credits valid for this [Section 5.3.3] as well?	<p>The Methodology was updated in Section 7.3 to clarify that the MRV Plan must be reviewed and approved by a jurisdictional authority (consistent with other requirements in Section 7.3.1) or, if no jurisdictional authority exists, by the VVB’s qualified professional expert in CCS. See Section 7.3.1 for further details.</p>
	Radicle	Requiring the VVB to determine adequacy of the MRV plan adds a new skill set to what is required for a verifier. Most will not have it -Are they expected to subcontract someone qualified to make that determination? Containment assurance is not a	

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		verifier’s traditional role. This will be an added burden and may be difficult to find verifiers to perform the task.	
99	Radicle	Last sentence last paragraph words are missing “As indicated in [blank spaces], no leakage...” check sentence for correct meaning being communicated.	The Methodology was updated to change the basis for determining the end of the post-injection period from verification of “no leakage” to verification of “plume stabilization.” The noted text was removed from the Methodology.
	Phillips 66 Company	Second to the last line [on page 95: ““As indicated in [blank spaces], no leakage...”], a section number is missing in the sentence.	
	Shell	There is a missing reference: “As indicated in [blank spaces], no leakage...”	
100	Carbon Engineering & 1PointFive	In our opinion, the buffer account would benefit by being moved from a straight 10% contribution of credits to a percentage contribution that is based on the risk profile of a specific project. Doing this would recognize the differences in durability of carbon storage between various CCS technologies, which is related to the surety of each element in the CCS chain.	The Methodology was updated to clarify that the Project Proponent would contribute a percentage of issued ERTs into the ACR-managed Reserve Account based on the risk profile of the project, as assessed according to the accompanying ACR CCS Reserve Account Contribution Tool (available on the CCS Methodology website).
	Drax	Risk rated determination of the buffer: The parametrization of the buffer is completely off. Scientific evidence indicates that 0.1-1% of CO ₂ may leak over a 1000-year period, which is magnitudes	The maximum amount deposited into the account shall be 10% (the default amount) and the minimum amount 2.5%, depending on

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		<p>different to the 10% buffer per year contemplated in the current methodology.</p> <p>Nature based vs. geological buffers: We believe the current buffer system proposed, which does not distinguish credits with nature-based storage and permanent geological storage is bound to draw market criticism and will not inspire confidence or willingness to pay. These buffer pools would need to be kept separate due to the vastly different nature and duration of storage they provide.</p>	<p>specific characteristics of the project jurisdiction and Project Proponent or Registry Participant.</p> <p>While ACR agrees that the typical project meeting the eligibility criteria of the Methodology is unlikely to result in reversals of this magnitude, the Reserve Account is established to ensure permanence of ERTs and compensate for reversals that are atypical. The Reserve Account would also be utilized for scenarios other than just unintentional emissions after injection, including if emissions during a Reporting Period exceed the Reporting Period's emission reductions and removals and if a project does not complete the full Crediting Period.</p> <p>The credit characteristics that must be met if the Project Proponent or Project Developer transfers credits to the Reserve Account in lieu of having the Reserve Account Contribution be deducted from the issuance (e.g., vintage and project type) is set forth in the ACR CCS Reserve Account Terms and Conditions. The Terms and Conditions also detail the requirements for further contributions in the event of emissions</p>
	Radicle	<p>Opting into an ERT reserve account at a 10% hold back rate is high. The rate could be set on a risk adjusted basis as determined by the expert weighing on the containment assurance based on criteria set by ACR. High risk = 5%, low risk is 1% and the experts assesses the risk. The idea that any vintage and type of ERTS can be deposited into the reserve account is concerning and leads to credibility issues and gaming, especially if the price of CCS credits are valued higher than other project types as expected. Where possible actual serialized credits, if have not been retired should be remitted. Or a % of the serialized credits issued from CCS project should be held back, not a reasonable surrogate.</p> <p>Include a section about Reserve account release</p>	

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		<p>process, if it applies (like Alberta Enhanced Oil Recovery Protocol) Address what happens to the 10% in the Reserve account after the crediting period and the period where permanence is assured (5 years post injection).</p>	<p>from activities prohibited by the Reversal Risk Mitigation Contract, the Reserve Account use criteria ACR refers to in determining the cancellation of carbon credits, and the disposition of credits at the end of the Minimum Project Term. The Reserve Account is maintained by ACR distinct from the Buffer Pool maintained for unintentional reversals from Agriculture, Forestry and Other Land Use (AFOLU) projects.</p>
	<p>Shell</p>	<p>How has ACR determined 10% as an appropriate reserve account allocation? This amount seems both arbitrary and excessively high given (1) the nature of CO₂ storage in saline formations, (2) the performance history of wells in both onshore and offshore environments, and (3) the call against current year credit claims before withdrawals are made from the Reserve Account.</p>	
	<p>Summit Carbon Solutions</p>	<p>This section provides two options for long-term liabilities: insurance or the creation of an ERT reserve account at a 10% deposit rate. Summit Carbon Solutions would recommend the use of a risk matrix in determining the reserve account deposit rate. Not all CO₂ storage sites are created equally and have inherently different risk profiles. Risk differences can arise from pore space ownership risks, legacy activity in the area of review, geological activity in the area of review, geologic profile of the storage site, among other factors. A risk matrix that provides for a dynamic deposit rate into the reserve account would</p>	

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		<p>more accurately reflect the risks associated with diverse projects.</p>	
101	Radicle	<p>Suggest reconsider the uncertainties on % CO₂. It is likely medium uncertainty although the frequency of measurement as once per month. A suggestion is to allow a default CO₂ concentration of the required pipeline spec to be used when measurement is missing or challenging. Also CO₂ leakage is likely medium uncertainty although there is a lack of measurement and engineering calculation required.</p> <p>Uncertainty of calculation for emissions from produced oil is high.</p> <p>Omission observed -Suggest updating table 9 to include all data parameters from Eq 29 PE transportation, PE refining, PE end use – if not those values, then the data parameter that are used to calculate those values as per App A. Applies to table 9 as well.</p>	<p>Table 9 (Potential Sources of Uncertainty) was changed into Table 7 (Monitoring Parameters), which includes all measured values from the equations in Section 6, including the frequency of %CO₂ measurements. The frequency of %CO₂ measurements must be either continuous or monthly.</p> <p>See Section 6.5 (Uncertainty) for details on uncertainty in CCS projects.</p> <p>As noted in the final version of the Methodology, oil produced via CCS projects will have a lower carbon footprint relative to other oil production. The Methodology, however, conservatively assumes that no oil production occurs in the baseline scenario (i.e., baseline oil production, processing and refining, transport, and end use emissions are zero) instead of assuming that oil is produced through other methods (with associated emissions through end use). Any potential uncertainty associated with the calculation of emissions from produced oil is outweighed by the conservatism</p>

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			of the overall approach.
102	Radicle	Fugitive – fugitives are unintentional leaks this is different from equipment that is designed to vent and release.	The Methodology was updated to distinguish between vented and fugitive emissions.
103	Radicle	This language in quotes below is confusing, please clarify the treatment of BECCS – Are you saying BECCS is not eligible as a project type or are you saying it cannot be negative? Would a biomass to power with CCS not be allowed entirely? If BECCS is eligible, then maybe add a few sentences to describe under what circumstances. "ACR does not include the potential negative carbon accounting from bioenergy carbon and storage (BECCS) as an eligible CCS project component in Version 2.0 of this Methodology, where ACR may include such negative accounting as an eligible component in future versions. Projects involving biomass should engage with ACR to determine eligibility."	See the responses to comments 4 and 58.
	Shell	Shell supports ACR’s efforts to broaden the quantification methodology to include sequestration of captured CO ₂ and carbon dioxide removals into saline formations and depleted hydrocarbon reservoirs. It is not clear in the document how BECCS	

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		<p>related removals will be quantified. The summary of changes document references eligibility for “CDR and sustainable biomass” yet Footnote 2 (pg 14) states “ACR does not include the potential negative carbon accounting from bioenergy carbon and storage (BECCS) as an eligible CCS project component in Version 2.0 of this Methodology.”</p>	
104	Radicle	<p>(Accuracy). When using a Standards based baseline the proponent should be required to measure at least once per year to demonstrate suitability of the Standard for the facility. Also in some cases, the standard may include other sources of emissions that are not relevant for the quantification, ie. Stationary combustion (not captured), venting from tanks (not captured) etc. Also, a standards based baseline is only appropriate when there is certainty that conservatism is being applied. If a facility is outperforming the standard, then the baseline would be overstated, and potentially materially overstated.</p>	<p>See the response to comment 7.</p> <p>The Methodology was updated to clarify that, where the Reporting Period involves a new calendar year, the VVB must verify the appropriateness of the intensity-based baseline (the new name for the standards-based baseline) each Reporting Period (see Section 7.1, Data Collection and Parameters to be Monitored). Additionally, the Methodology was updated to state that “projects in which a primary CO₂ source is subject to an emission intensity metric or limit must calculate both a project-based baseline [formerly the “project-based baseline] and intensity-based baseline [formerly the “standards-based baseline”] and use the most conservative (lowest) baseline”</p> <p>Projects subject to more complicated regulatory requirements or performance</p>

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			standards may need to consult with ACR.
105	Ruby Canyon Environmental	Should projects in development be included to be eligible at the time the version 2.0 of the methodology is published? This to broader [sic] the potential projects that can utilized this methodology, because it is believed, there are still few CCS projects, even in the US.	Projects in development are eligible at the time v2.0 of the Methodology is published if they meet the eligibility requirements in the Methodology and the <i>ACR Standard</i> .
106	Ruby Canyon Environmental	A highlight error regarding a reference source not found is at the first paragraph of the section [2].	The noted typographical error was corrected.
107	Ruby Canyon Environmental	Adjust Figure 1 title to display: “Project boundaries -” before “Sources, Sinks and Reservoirs.”	The Methodology was updated to move the Figure 3 title (Project Boundary Diagram for CCS Project) before the figure.
108	Ruby Canyon Environmental	Now that the 2022 Global Status Report has been submitted at the time the Methodology 2.0 Draft was published, should the data contained in the document be revised for the final Methodology published? https://status22.globalccsinstitute.com/	The Global Status of CCS 2024 from the Global CCS Institute was cited in the updated Methodology.

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109	Ruby Canyon Environmental	Regarding the underestimation of CO ₂ capture due to the functional equivalence, could this be better explained such as making it clearer that because the CO ₂ capture system consumes electricity from the power generation plant, The ready-available energy to be utilized in other activities different from the capture system is going to be less by burning the same quantity as per the baseline? Otherwise, it is understood as that the capture system could cause less electricity generation by itself.	The language about output comparisons was removed from the Methodology and Section 6.1.1 (Functional Equivalence) was updated to state, among other things, that the “key consideration in applying the principal of functional equivalence to the baseline is ensuring that the baseline reflects what CO ₂ would have been produced in the absence of capturing CO ₂ from the CO ₂ source.”
110	Shell	Clarification sought: Regulations may be structured to provide alternative compliance pathways for, say, meeting a performance standard. For example, perhaps compliance can be demonstrated on a portfolio basis rather than on an individual asset basis. Where this is the case, would the application of CCS at a facility down to the regulatory performance standard necessarily be deemed non-creditable? Alternatively, might the applicant pursue credits for the full amount of net emission reductions via CCS while relying on other pathways to meet the regulatory standard?	In jurisdictions where regulations have compliance pathways different from the emission intensity standard discussed in Section 6 of the Methodology, only emission reductions that go beyond the legal requirements are eligible for crediting. See also responses to comments 7, 61, and 89.

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111	Shell	<p>Application of a performance standard as an additionality test can be arbitrary or else undefined. The proposed methodology references practice-based tests and/or technology-based, both of which leave the important thresholds undefined. Use of the term “sufficiently low” and allowing it to be judged against an industry, sector or subsector “within the specific region” leaves significant uncertainty as to how the practice-based tests will be applied. Similarly, that which constitutes a “GHG-reducing technology” is also undefined. For example, would the use of a pre-combustion capture technology instead of a post-combustion technology be credit worthy simply by being “sufficiently uncommon”? While it is difficult to establish hard limits for these types of tests, deferring these decisions to a later date creates uncertainty for project developers.</p>	<p>The performance standard section of the Methodology was updated extensively to clarify what activities are eligible under the performance standard.</p>
112	Shell	<p>Does ACR consider mineral CO₂ (CO₂ co-produced with natural gas) to be an anthropogenic emission source eligible for carbon credits?</p>	<p>Natural gas processing CO₂ can be eligible as a CO₂ source if the conditions outlined in Section 2.V. are met.</p>

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113	Shell	<p>What is the justification to exclude emissions associated from the transport, refining and end use of hydrocarbons produced by EOR products for the first five years of operation or until January 1, 2030, whichever is first? The methodology assumes any displaced barrel would have a higher carbon intensity, and that the US is the relevant boundary for assessing net emission impacts. The Clean Air Task Force (https://www.catf.us/resource/CO₂-eor-emission-reduction/) cites IEA work on this topic: "IEA's global oil market analysis estimates that when oil produced through CO₂-EOR hits the global market, 84% of EOR-supplied oil displaces existing supply and satisfies existing oil demand. The remaining 16% percent represents an increase in oil supply, which lowers the price of oil and results in increased oil consumption."</p>	<p>The Methodology has been substantially updated as it relates to the referenced language. See the responses to comments 47 and 96.</p>
114	Shell	<p>"Common practice" for new facilities is open to interpretation. However, setting a baseline according to the "most economic option" may be very difficult for the Proponent and ACR to prove.</p>	<p>The term "most economic option" was removed from the Methodology and eligibility is no longer outlined in terms of the newness of CO₂ sources.</p>

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115	Shell	“Units of output from the CO ₂ capture facility” should be rephrased as “Units of output from the facility from which CO ₂ is being captured.” The output of the CO ₂ capture facility is CO ₂ .	The units for the intensity-based baseline approach have been clarified and are accurately described as “total production unit of output (e.g., MWh, MMscf).” Because intensity-based standards cannot (by law) exceed a specific intensity limit that is based on the production unit of output, the use of this term is appropriate to establish the emissions that would have occurred in the absence of the project (i.e., baseline emissions).
116	Shell	“If emissions are captured and sequestered...” then they are not “emissions.” Better to rephrase this as “If GHGs are captured and sequestered, they are not considered project emissions because they are not released into the atmosphere...” There are instances elsewhere in the protocol that describe captured GHGs as “emissions.”	Section 6 of the Methodology was updated to more clearly differentiate between CO ₂ produced, captured, and emitted from a CO ₂ source.
117	Shell	What is meant by “the modeled failure scenarios”? It is not clear in what respect these are “failure” scenarios if the CO ₂ remains contained within the storage volume.	The Methodology was updated to change the phrasing to “failure scenarios” (see Section 7.3.5, Area of Review and Corrective Action Plan), which refers to scenarios under which CO ₂ could be emitted to the atmosphere, resulting in geologic storage reservoir emissions.

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118	Shell	What purpose is achieved by allowing ERTs deposited in the Reserve Account to come from another project of any type and any vintage?	The Methodology was updated to remove reference to the credit characteristics that must be met if the Project Proponent or Project Developer transfers credits to the Reserve Account in lieu of having the Reserve Account Contribution be deducted from the issuance (e.g., vintage and project type), and this is instead set forth in the ACR CCS Reserve Account Terms and Conditions. Each carbon credit issued on ACR is considered equally fungible and to represent an equal benefit to the atmosphere, no matter the project type, location or vintage. Accepting credits from project activities that are not reversable into the Reserve Account serves the objective of ensuring that, in the event of a reversal, any losses are effectively compensated and the atmosphere “made whole.”
119	Shell	Leakage is compensated for by current year credits and then ERTs in the Reserve Account. The final paragraph of this section states what will happen if there are not sufficient ERTs in the Reserve Account: “If the Project Proponent does not deposit sufficient ERTs to mitigate the leakage within 45 days, then ACR retains the right to freeze the Proponent’s project	The permanence section of the Methodology was updated extensively to clarify how reversals shall be compensated for. The legally binding Reversal Risk Mitigation Contract provides remedies in the event of a default (e.g., if the Project Proponent fails to contribute credits to compensate for a reversal not

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		account and retire any existing ERTs to mitigate the unreconciled quantity.” Where will ACR get the ERTs to mitigate the unreconciled quantity?	covered by the Reserve Account) to ensure that an appropriate quantity of credits are cancelled to compensate for a reversal.
120	South Pole	<p>Footnote 2 "ACR does not include the potential negative carbon accounting from bioenergy carbon and storage (BECCS) as an eligible CCS project component in Version 2.0 of this Methodology, where ACR may include such negative accounting as an eligible component in future versions. Projects involving biomass should engage with ACR to determine eligibility."-Definition of sustainable biomass in the ACR guidelines document (page 84). Additionally, the "CARBON CAPTURE AND STORAGE PROJECTS methodology v.2.0", which is under scientific peer review, mentions in footnote 2 on page 15 the need to engage with ACR to determine the eligibility of projects involving biomass.</p> <p>Could you provide any additional guidelines or resources to help our client develop a sustainable biomass sourcing strategy?</p>	See responses to comments 58 and 59.
121	Summit Carbon Solutions	Carbon Capture and Storage projects can be organized as a hub model with multiple source points of carbon capture with common transport and storage infrastructure. The different source points	The Methodology provides clear project boundaries and the <i>ACR Standard</i> provides direction on how to ensure that double counting does not occur.

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		<p>could be in a situation where the benefit of carbon capture and storage are recognized in different markets. For example, CO₂ captured from ethanol production could be recognized in compliance markets (i.e. California Low Carbon Fuel Standard market) as well as voluntary markets, as long as double counting is avoided. The methodology does not appear to provide a framework for allocating CO₂ across various markets while ensuring there is no double-counting. This will severely limit the applicability of this methodology to large scale projects with multiple and variable sources of carbon capture. Summit Carbon Solutions recommends that ACR update the methodology quantification and other relevant sections to provide this flexibility to Project Proponents and safeguards against double counting.</p>	<p>See also the response to comment 2.</p>
122	Summit Carbon Solutions	<p>The methodology appears to be inconsistent in the classification of removals vs. reductions of the quantified impacts. In the definitions on page 107, “Carbon Dioxide Removal” definition includes BECCS and BiCRS. The BiCRS definition on page 5 is identified as a removal and the BECCS definition does not specify a removal or reduction. In section 1.2, footnote 2 on page 14, BECCS is excluded as a removal. In section 4.1.4 on page 34, only DACCS is</p>	<p>See the responses to comments 3 and 4.</p>

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		<p>identified as a removal. These conflicting sections make it unclear on what activities the methodology intends to classify as a removal, particularly with respect to BiCRS. Summit Carbon Solutions recommends that greater clarity and consistency be incorporated into the methodology.</p>	