U.S. Early Plugging of Marginal Oil and Gas Wells

Workgroup Draft Version 1.0

March 27, 2026

NOT FOR PUBLIC COMMENT

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Partial Technical Support

This document was developed with partial technical support from ClimateWells, in collaboration with the Rocky Mountain Institute, EcoEngineers, and Netherland, Sewell & Associates.

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Abbreviations and Acronyms

AoR	Area of Review
API	American Petroleum Institute
BLM	Bureau of Land Management
BOE	Barrel of Oil Equivalent
BOEPD	Barrels of Oil Equivalent Per Day
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DCA	Declined Curve Analysis
EIA	Energy Information Agency
IOGCC	Interstate Oil and Gas Compact Commission
LCA	Lifecycle Assessment
M	One Thousand
MM	One Million
Mcf	Volume of 1,000 cubic feet
N_2O	Nitrous Oxide
NYMEX	New York Mercantile Exchange
O&G	Oil and Gas
OCI+	Oil Climate Index Plus
OGIP	Original Gas in Place
OOIP	Original Oil in Place
OPEM	Oil and Gas Products Emissions Module
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
P&A	Plug & Abandon
PPEF	Professional Petroleum Engineering Firm
PPM	Parts Per Million
PRELIM	Petroleum Refinery Life-Cycle Inventory Model
PRMS	Petroleum Resource Management System
QlPR	Qualitative Permanence Review
QnPR	Quantitative Permanence Review
SPE	Society of Petroleum Engineers
T or tonne	Metric Ton
WTI	West Texas Intermediate

1 Introduction

The Climate Action Reserve (Reserve) Early Plugging of Marginal Oil and Gas Wells Protocol provides guidance to account for, report, and verify greenhouse gas (GHG) emission reductions associated with the early decommissioning of marginal, productive, and economically viable oil and gas wells.

The Climate Action Reserve is the most trusted, efficient, and experienced offset registry for global carbon markets. A pioneer in carbon accounting, the Reserve promotes and fosters the reduction of greenhouse gas (GHG) emissions through credible market-based policies and solutions. As a high-quality offset registry for voluntary carbon markets, it establishes rigorous standards and issues carbon credits under those standards. The Reserve also supports compliance carbon markets and serves as an approved Offset Project Registry for the State of California's Cap-and-Trade Program, or the Washington Cap-and-Invest Offsets Program. The Reserve is an environmental nonprofit organization operating virtually worldwide, with a small physical office located in Los Angeles, California. For more information, please visit www.climateactionreserve.org.

Project developers that initiate early decommissioning projects use this document to quantify and register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve Verification Program Manual[1] and Section 8 of this protocol.

The Reserve develops protocols aligned with the laws, norms, and on-the-ground context of a specific jurisdiction or jurisdictions to establish standardized eligibility and additionality criteria and baseline scenarios. This protocol is thus aligned with the laws, norms, and context of current oil and gas and methane regulations. See Section 3.5 and 5.1 for further information.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a project.[2]

[1] Available at https://climateactionreserve.org/how/program-resources/program-manual/

[2] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

2 The GHG Reduction Project

2.1 Background

The number of productive wells in the United States was over 918,400 wells in 2024, yet only 20% of the wells represent over two-thirds of domestic oil and natural gas production.[3] Wells that produce lower quantities of oil and natural gas on a daily basis have high emission profiles and account for about 50% of the sector's emissions.[4,5] Many of these lower productive wells have been producing for over 50 years and will continue to extract oil and gas for decades. The Protocol incentivizes these economically viable oil and gas wells to be decommissioned early and leave hydrocarbons unextracted.

As the world transitions to a carbon-neutral economy, and existing wells continue to age, the number of wells that need to be plugged will likely increase.[6] Remediation of marginal wells in the near term could result in immediate positive environmental impacts on the quality of water, air, climate, and human ecosystem health with the added societal benefits such as the wellbeing of nearby communities, job creation, and economic stimulation.

2.2 Project Definition

The GHG reduction project is defined as the avoidance of production- and use-associated GHG emissions from a marginal oil and gas well by plugging the well early and keeping hydrocarbons underground. Plugging an otherwise economically viable oil and/or gas well will prevent GHG emissions throughout the lifecycle of the associated hydrocarbons, including extraction, processing, transportation, refining, and end-use.

For the purposes of this protocol, a marginal oil and gas well is defined in relation to the following criteria:

1. Actively producing: project developer must demonstrate that the well has been extracting oil and/or gas in each of the previous 12 months preceding the project start date.
2. Low production: The average production rate must be equal to or less than 75 barrels of oil equivalent (BOE) per day or 450 thousand cubic feet (Mcf) of natural gas.[7]
3. Past its terminal decline and future production is predictable: the point at which the forecasted production decline rate becomes constant and is assumed to remain at that rate for many years or decades (see Section 3.4.1.1 and 3.4.1.2).
4. Not yet orphaned and abandoned: achieved through demonstrating ownership of the well through clear and explicit title (see Section 2.3)

Project developers must undertake the activities associated with the early decommissioning and plugging of marginal oil and gas wells in the United States. The plugging and abandonment (P&A) of the project well must be completed in accordance with federal, state, local, and tribal

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[3] According to the U.S. Energy Information Administration report released December 2025. Available at: https://www.eia.gov/petroleum/wells/

[4] GSI Environmental Inc. (April 2022). *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* U.S. Department of Energy [US DOE NETL Award Number DE-FE0031702].

[5] Omara, M. et al (2022). Methane emissions from US low production oil and natural gas well sites. *Nature Communications*

[6] Orphaned oil and gas well stimulus—maximizing economic and environmental benefits M Kang, AR Brandt, Z Zheng, J Boutot, C Yung - Elem Sci Anth, 2021

[7] The US Department of Energy defines marginal wells as 15 BOE/day or 90 Mcf/day for natural gas. However, based on workgroup expertise, the protocol has a higher production rate to not exclude otherwise additional oil and gas wells under the protocol.

regulations and requirements, including receiving the required permits. Wells are considered P&A the date that they are certified as P&A on the state's public database or government agency documents

Multiple wells may be considered under a single project if the wells have the same owner/operator and are located within the same geological oil and gas reservoir. Each well must meet the additionality criteria in Section 3 and emission reductions are quantified on a well-by-well basis according to Section 5. The Protocol does not allow for project expansion—after the project completes its initial verification, no new wells may be added to the project.

2.3 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. The well owner and/or operator has ownership of the hydrocarbons through a contract or lease with the mineral estate, and thus, has the ownership of the emission reductions. However, the well owner/operator may choose to hire a third-party project developer to complete project reporting and verification. In such cases, the well owner/operator may transfer the rights to the emission reductions to another entity.

Project developers may be the project well owner, well operator, entities that specialize in project development, or other entities. Regardless of the type of entity, the project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, such as through a legal contract to transfer the rights to the project's GHG emission reductions to another entity.

Each time the project is verified, the project developer must attest that no other entities are reporting or claiming (e.g., for voluntary reporting or regulatory compliance purposes) the GHG reductions caused by the project activity by signing the Reserve's Attestation of Title form.[8]

[8] Attestation of Title form available at https://climateactionreserve.org/how/program-resources/forms/

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

3.1 Location

Only projects located in the United States, its territories, and on U.S. tribal lands are eligible to register with the Reserve. Eligible oil and gas wells may be located on either private or public lands.

3.2 Project Start Date

The project start date is defined as the date the well is certified as P&A on the relevant state's public database or government agency documents. P&A must be completed for each well in accordance with the minimum requirements established by the Bureau of Land Management[9] (for public lands), applicable state regulations (for private lands), and/or tribal requirements. For projects including multiple wells, each well will have its own start date and must be P&A within 12 months of the first well plugged, though the overall project start date will be based on the certification date of the first plugged well.

To be eligible, the project must be submitted to the Reserve no more than twelve months after the project start date.[10,11] Projects may be submitted for listing prior to the project start date.

3.3 Project Crediting Period

The Reserve will issue Climate Reserve Tonnes (CRTs) for GHG reductions quantified and verified using this protocol for an initial crediting period of 10 years following the project start date. If multiple wells are reporting under a single project, the project's crediting period may exceed 10 years only when each well within a given project is not plugged on the same day. However, each individual well is only eligible for a maximum of 10 years. A crediting period may be less than 10 years if the well's economic limit (see Section 3.4.1.3) is less than 10 years from the project start date, such that the project's crediting period is limited to the length of the well's remaining economic life.

At the end of a project's first crediting period, project developers may apply for eligibility under a second crediting period, for a project lifespan of 20 years. However, the Reserve will cease to issue CRTs for GHG reductions if at any point in the future, the early plugging of marginal oil and gas wells becomes legally required, as defined by the terms of the legal requirement test (see Section 3.4.2), or if the project well is re-opened after P&A. Thus, the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of two ten-year crediting periods after the project start date, or until the project activity is required by law.

If a project's economic life exceeds 20 years, only 20 years' worth of emissions will be eligible for crediting, unless the project can demonstrate legal permanence. If a project meets the

[9] Bureau of Land Management (1988), available at: http://www.mt.blm.gov/oilgas/op

[10] Projects are considered submitted when the project developer has fully completed and filed the appropriate Project Submittal Form, available on the protocol webpage.

[11] If multiple wells are reporting under a single project, the submittal deadline is based on the earliest date on which a project well is plugged.

criteria for legal permanence outlined in Section 5.1.1, then the avoided emissions attributed to the full economic life may be issued after the initial verification.

The project crediting period begins at the project start date regardless of whether sufficient monitoring data is available to verify GHG reductions. Projects will be eligible to apply for a second crediting period, provided the project meets the eligibility requirements of the current version of the protocol at the time of such application. If a project developer wishes to apply for eligibility under a second, 10-year crediting period, they must do so no sooner than six months before the end date of the initial crediting period.

3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of the carbon market.

Projects must satisfy the following tests to be considered additional:

1. The performance standard test
2. The legal requirement test

Furthermore, a project must also not be receiving other financial incentives, as described in Section 3.4.3.

3.4.1 The Performance Standard Test

Projects pass the performance standard test by meeting a performance threshold, i.e., a standard of performance applicable to all marginal oil and gas well projects. The performance standard test employed by this protocol is based on a national and state level assessment of "common practice" for oil and gas production and decommissioning.[12] The performance standard test is applied at the time of a project's start date.

The early, voluntary decommissioning of wells that are still marginally productive is not common practice in the U.S. oil and gas sector. Operators typically delay decommissioning until wells are completely uneconomic or regulators compel action. Under the protocol, only reserves that remain economically viable are eligible for crediting (see Section 3.4.1.1 and Section 3.4.1.2). A project passes the performance standard test by showing that, at the time of the project start date, the project activity results in the decommissioning of a well that is otherwise still economically viable.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of the protocol, including any updates to the performance standard test.

3.4.1.1 Determination of Economic Reserves

Oil and gas reserves are classified based on the certainty of recovery, and defined by the Petroleum Resources Management System (PRMS):[13]

- Proved Reserves ("P1"): quantities that can be estimated with a reasonable certainty (at least 90% probability) to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

[12] See Appendix A for more information on the performance standard test analysis.
[13] Available at: https://www.spe.org/en/industry/reserves/

- Probable Reserves ("P2"): quantities that are less likely to be recovered than proved reserves, but more certain (at least 50% probability) to be recovered than possible reserves.
- Possible Reserves ("P3"): quantities that are less likely (at least 10% probability) to be recoverable than probable reserves.

P1 reserves are accessible through traditional extraction methods, such as horizontal and/or vertical drilling, while P2 reserves require enhanced recovery methods, such as water flooding or injection. Enhanced recovery methods have become less expensive in recent years, resulting in P2 reserves becoming more extractable. However, only P1 reserves (i.e., economic reserves) are eligible for crediting under the protocol.

The well's economic reserves must be evaluated by a qualified independent, third-party Professional Petroleum Engineering Firm (PPEF), as defined in Section 3.4.1.1.1. If multiple wells are reporting under a single project, the same PPEF must conduct all evaluations. The economic reserves must be evaluated in accordance with the most recent version of the PRMS and Guidelines for the Application of the Petroleum Resources Management System. PPEF may use their professional judgement to determine which analysis procedure(s) to use based on the well and reservoir characteristics. The PPEF should use more than one analysis method to determine the economic reserves. In instances where the quantity of economic reserves differs between analyses, then the most conservative value must be used for purposes under the protocol. The evaluation report must include a narrative of the analyses used and the estimated economic reserves from each analysis.

The report must clearly state the total quantity of economic reserves recoverable during the well's economic life, as well as the reserves attributed to the first 10 years of the project and the quantity recoverable in the subsequent 10 years.

The PPEF report must be completed no earlier than 12 months prior to the date the well completes P&A activities, or the economic reserves must be re-evaluated. The economic reserves evaluation report must be submitted to the verification body and to the Reserve during verification.

If the well continues to extract hydrocarbons while the economic reserves are being assessed and before the well is certified as P&A, then the quantities of extracted reserves must be deducted from the reserves identified in the PPEF report. The PPEF report must be updated with an addendum (or similar modification) to the report to revise the economic reserves. The project developer must retain all documentation related to the ongoing extraction and production of hydrocarbons prior to the well being certified as P&A.

3.4.1.2 Reservoir Communication and Permanence Risk

Due to the permeability of oil and gas reservoirs, sequestered economic reserves may be accessible by nearby wells or the voluntary P&A of a well or series of wells may result in an increase in production at a nearby well. This results in a risk that the sequestered reserves are not permanent. A permanence discount is applied to account for this risk.

The PPEF must determine the Area of Review (AoR) by identifying structural, stratigraphic, and petrophysical features, and pressure communication limits. All wells within the AoR, regardless of the status (i.e., active, idle, shut in, P&A, orphaned), must be assessed according to Appendix D.2 to determine the risk of the non-project well accessing the sequestered reserves.

If the PPEF can demonstrate with reasonable certainty that there is negligible reservoir communication between the project well and wells within the AoR, then no permanence discount is required. However, if a portion may be produced by another well or the PPEF cannot demonstrate with reasonable certainty reserves may not be produced by another well, then a secondary, qualitative permanence review is required.

The qualitative permanence review (Appendix D.3) requires the PPEF to determine the percentage of sequestered reserves that are economically recoverable from a non-project well and the conclusiveness of the available data and associated analysis. A 5% permanence deduction or 20% permanence deduction is applied to projects that have a low or medium percent of reserves recoverable from other wells, respectively.[14] Projects with a high risk of sequestered reserves being accessed by a well within the AoR are not eligible. Permanence discounts are applied to the adjusted economic reserves in Equation 5.#.

Projects must also apply an uncertainty discount to the baseline emissions in Equation 5.2 associated with the conclusiveness of the data used to assess reservoir communication. If the PPEF determines that there is low data conclusiveness, then a 5% discount must be applied. If there is medium data conclusiveness, then a 1% discount is required.[15] Projects with high data conclusiveness are not required to apply an uncertainty discount.

3.4.1.3 Determination of Economic Limit

Projects are required to demonstrate that the project well remains economically viable, and the early plugging of the well is not financially advantageous as of the project start date. To do so, the project developer must determine the economic limit (i.e., production rate when the project reaches the maximum cumulative net operating cash flow) of each well according to the PRMS.

The economic limit for each well must be evaluated by the PPEF in accordance with the PRMS and PRMS Application Guidelines. In instances where the PRMS and this protocol differ, the protocol takes precedence.

The estimated revenue from the economic reserves (as defined by the PPEF) represents the business as usual scenario if the well continued to extract hydrocarbons until all economic reserves are depleted. The most recent U.S. Energy Information Agency (EIA) Annual Energy Outlook[16] (AEO) report available at the time of the evaluation must be used to determine the future price of the economic reserves. Project developers must use the reference case price model for the Henry Hub natural gas spot price or the West Texas Intermediate spot crude oil prices. When forecasting revenue from the economic reserves, the evaluation must be conducted on a year-by-year basis, such that the production in a given year is multiplied by the AEO forecasted price for that year. If the economic life exceeds the AEO forecasted prices, then the latest price available should remain constant through the project's economic limit date.

The expenses associated with continued operation until all economic reserves are extracted should be determined using the 12 months of historical operating records for the project well prior to the PPEF evaluation date. During verification, the project developer must demonstrate that the operating costs are typical for the wellfield and the average costs from the lease operating statement are representative of the industry.

[14] Refer to Appendix D.3.2 for defining low, medium, and high.
[15] Refer to Appendix D.3.3 for defining low, medium, and high.
[16] EIA Annual Energy Outlook is released every spring and forecast prices through 2050. Most recent report is available here: https://www.eia.gov/outlooks/aeo/

During verification, the project developer must provide the financial assessment, operating expense records, the source(s) used for carbon pricing estimates, calculation workbook(s) used to determine the economic limit, and other relevant documentation for the verifier to reach reasonable level of assurance.

The project must re-evaluate the economic limit at the time of crediting period renewal based on the revised EIA AEO future prices to demonstrate the project remains additional. The same PPEF that conducted the initial assessment should conduct the re-assessment, unless granted approval from the Reserve.

3.4.1.4 Professional Petroleum Engineering Firm Eligibility

To ensure independence of the PPEF, all projects must demonstrate a low conflict of interest (COI) between the PPEF and parties involved in the project during verification. A COI is defined as any situation that compromises a PPEF's ability to perform a wholly independent evaluation. In order to ensure the credibility of the emissions data reported to the Reserve, it is crucial that the PPEF is completely independent from the influence of the project developer or other entities involved in the project. For more information on the conflict of interest refer to Appendix B.

Project developers are required to complete the Professional Petroleum Engineering Firm Qualifications and Conflict of Interest Assessment form.[17] All potentially conflicting services and conditions must be reported to the verification body and the Reserve during the initial verification of each crediting period. Failure to report a conflict of interest will result in the project being ineligible for crediting or require further action by the Reserve. Proceeding to evaluate economic reserves with a medium or high conflict of interest between parties may result in the project being ineligible or the economic reserves being required to be re-assessed by another PPEF.

All assessments conducted by the PPEF under the scope of the protocol must be conducted by a qualified Petroleum Engineer and Petroleum Geologist. Qualified is defined as being certified within the state for which the project well(s) is located. All reports produced for use under this protocol must be signed by the designated Petroleum Engineer and Petroleum Geologist.

3.4.2 The Legal Requirement Test

All projects are subject to a legal requirement test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the legal requirement test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the early plugging of the project well(s). Additionally, project developers must demonstrate that applicable plugging obligations, if any, are not applicable as of the project start date, and each reporting period thereafter.

To satisfy the legal requirement test, project developers must submit a signed Attestation of Voluntary Implementation form[18] prior to the commencement of verification activities each time the project is verified (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the legal requirement test. If a regulatory agency with authority over the well passes a rule obligating the early plugging of the project well(s), emission reductions

[17] Form is available on the protocol webpage.
[18] Attestation forms are available at https://climateactionreserve.org/how/program-resources/forms/

can be registered with the Reserve from the project start date until the activity becomes legally required.

At the time of protocol adoption, the early, voluntary decommissioning of marginally productive oil and gas wells are not legally required in the United States. While most states impose legal requirements to plug wells prior to abandonment, the plugging of marginally productive wells prior to their financial end-of-life is not common practice.

3.4.3 Other Incentives

Other types of incentives may exist for early decommissioning and plugging a marginal well that could impact project additionality, including credit stacking, payment stacking, and real estate value.

When multiple forms of incentive credits are sought for a single activity at a single facility or on a single piece of land, with some temporal overlap between the different credits or payments, it is referred to as “credit stacking” or “payment stacking,” respectively.

3.4.3.1 Credit Stacking

Under this protocol, credit stacking is defined as receiving both carbon credits and other types of mitigation credits for the same activity on spatially overlapping areas associated with any phase of a marginal well project. Mitigation credits are any instruments issued for the purpose of offsetting the environmental impacts of another entity. At the time of development, the Reserve did not identify credit stacking incentives related to the project activity being credited under the protocol.

3.4.3.2 Payment Stacking

Payment stacking is defined as receiving payments for decommissioning and plugging a marginal well under this protocol while being funded by the government or other parties via grants, subsidies, payment, etc., for the same activities on the same land or well site. The Reserve identified one general type of payment that supports the activities being credited under this protocol, called “reimbursement payments.”

“Reimbursement payments” refer to payments from federal or state programs that provide funding opportunities to incentivize voluntary plugging of marginal wells to eliminate the risk of them being orphaned. The term “reimbursement” is not to limit application to funding opportunities that issue payment after the P&A has been completed, but to reflect common procedure. Funding granted prior to P&A is considered under this incentive.

Wells operated by oil and gas wellfield operators that participate in large-scale voluntary well retirement programs funded by non-carbon market sources are not eligible under the protocol. Project developers must demonstrate this during verification to a reasonable level of assurance by referencing:

1. Historical decommissioning data
2. Relevant public datasets (e.g., Enverus, state well files)
3. Industry reports or regulator surveys

The U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE) provide financial assistance through several grant opportunities, either issued to the state or individual projects, under the Methane Emissions Reduction Program (MERP).[19] Grants are either issued to individual projects or issued to states – Texas, Pennsylvania, West Virginia, California, Ohio, Illinois, Louisiana, New Mexico, Kentucky, Colorado, New York State, Michigan, Utah, and Virginia – to support reducing emissions in the oil and gas sector.

These funding opportunities are typically limited to idle or producing onshore oil or natural gas wells producing less than or equal to 15 BOE and/or 90,000 cubic feet of gas per day over the prior 12-month period.

Wells that are not eligible to receive grants under such programs are eligible under the protocol. Wells that would otherwise be eligible must attest that they were not recipients of such grants. Verifiers shall confirm that the site is not listed as a recipient of the grant under applicable state agency documentation.

Project developers must disclose any such payments to the Reserve at the time of listing and to the verification body and the Reserve at the time of verification. The Reserve maintains the right to determine if stacking has occurred, or is occurring, and whether it would impact project eligibility.

3.4.3.3 Real Estate Value

A well owner/operator may be incentivized to decommission and plug a well early based on the potential real estate value of the land. Projects where the well is owned and/or operated by the same entity that owns the surface estate must demonstrate that the financial benefit of the real estate land value after the well is P&A minimal through a real estate appraisal.

An appraiser must clearly indicate change in real estate value of the surface land applicable to the project well boundary. The appraisal must conform with the following minimum standards:[20]

1. Appraisal reports shall be prepared and signed by a third-party, Licensed or Certified Real Estate Appraiser in good standing
2. Appraisal reports shall include descriptive photographs and maps of sufficient quality and detail to depict the subject property and any market data relied upon, including the relationship between the location of the subject property and the market data.
3. Appraisal reports shall include a statement by the appraiser indicating to what extent land title conditions were investigated and considered in the analysis and value conclusion.
4. Appraisal reports shall include a discussion of implied dedication, prescriptive rights or other unrecorded rights that may affect value, indicating the extent of investigation, knowledge, or observation of conditions that might indicate evidence of public use.
5. The appraisal must be conducted in accordance with the Uniform Standards of Professional Appraisal Practice[21] and the appraiser must meet the qualification standards outlined in the Internal Revenue Code, Section 170 (f)(11)(E)(ii).[22]

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[19] For more information, please refer to the Inflation Reduction Act, Financial Assistance from the Methane Emissions Reduction Program. Available at: https://www.epa.gov/inflation-reduction-act/financial-assistance-methane-emissions-reduction-program

[20] Adapted form Sections 5096.501 and 56096.517, Public Resources Code, State of California and Reserve's U.S Grasslands Protocol V2.1.

[21] The Uniform Standards of Professional Appraisal Practice may be accessed at: http://commerce.appraisalfoundation.org

[22] Section 170 (f)(11)(E) of the Internal Revenue Code defines a qualified appraiser as "an individual who: (I) has earned an appraisal designation from a recognized professional appraiser organization or has otherwise met minimum education and experience requirements set forth in regulations prescribed by the Secretary, (II) regularly

3.5 Regulatory Compliance

Project activities must not cause material violations of applicable environmental and worker safety laws (e.g., air, water quality, safety, etc.), as well as all plugging and abandonment regulations. To satisfy this requirement, project developers must submit a signed Attestation of Regulatory Compliance form[23] prior to the commencement of verification activities each time the project is verified. Project developers are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project activities.

A violation should be considered to be “caused” by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to “acts of nature,” are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to project activities may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

Additionally, project developers and oil and gas well owners and/or operators with reoccurring regulatory violations at the project well(s) prior to the project start date may be denied listing at the discretion of the Reserve.

3.5.1 Limitations on Burdening Mineral Rights

In states with oil and gas development, surface rights and mineral rights are typically legally separated, and considered distinct sets of rights. For example, under Texas law, when the surface estate is different from the mineral estate, the mineral estate takes precedence, and the owner has the right to use the surface land to the “extent reasonably necessary for the exploration, development, and production of the oil and gas under the property.”[24] To protect the mineral estate, states may strictly limit one party’s ability to retire, extinguish, restrict, or otherwise burden mineral interests of another.

This protocol does not seek to retire, extinguish, restrict, or otherwise burden mineral interests belonging to another. Instead, the protocol assumes that there is a low likelihood[25] of new marginal wells being drilled close to the decommissioned well due to the significant costs of drilling and exploration compared to the low quantity of economic reserves. Alternatively, mineral estates may voluntarily sell the mineral estate to another entity. If the project developer purchases the mineral estate and retires the mineral rights through a conservation easement, proof of ownership to the mineral estate and the conservation easement must be provided during verification.

Additionally, in practice, plugging a marginal well is not considered to be in conflict with regulations protecting mineral rights. State agencies approve and issue permits granting an

performs appraisals for which the individual receives compensation, and (III) meets such other requirements as may be prescribed by the Secretary in regulations or other guidance.”

[23] Attestation forms are available at https://climateactionreserve.org/how/program-resources/forms/

[24] Railroad Commission of Texas.

[25] Although unlikely, the protocol includes several safeguards to ensure credited reserves are not accessed. If reserves are accessed, then the project is no longer eligible for crediting.

operator's ability to plug a marginal well, which sets legal compliance of the plugging operations and grants the operator's rights to plug the well. Authorization or notification to the mineral estate is often not required, unless there is a Producers 88 lease between the mineral estate and the well operator that requires the notice, consent, or minimum production thresholds. If there is a Producers 88 lease, or equivalent requirement in the lease agreement, the project must demonstrate compliance with the lease during verification.

Leases may require well operators to act as "reasonably prudent operators." Because marginal wells produce high emissions and relatively low production, early plugging of the well may be considered prudent. Alternatively, continued production may also be considered prudent if the operator maintains regulatory compliance. Thus, early P&A is not considered to be in conflict with this lease requirement.

3.6 Social and Environmental Safeguards

The Reserve requires project developers to demonstrate that their GHG projects will not give rise to environmental or social harm. Moreover, offset projects can create long-term social and environmental benefits and have the potential to improve quality of life for nearby communities, both in terms of increased revenues and in terms of sustaining and improving oilfield practices.

This Protocol includes specific social and environmental safeguards that must be considered in the project design and implemented throughout the project life to help guarantee that the project will have positive environmental and social outcomes. In addition, all projects must comply with the Reserve's Offset Program Manual, including the section on regulatory compliance and programmatic environmental and social safeguards. The safeguards in the protocol are intended to respect governmental processes, customs, and rights of asset owners while ensuring projects are beneficial, both socially and environmentally. Sections 6 through 8 specify the criteria for the monitoring, reporting, and verification of each of these safeguards and consequences for failure to achieve the minimum thresholds.

The social safeguards requirements include:

1. Notification of Plugging: The project developer must notify all parties as defined in the well's operating permits, environmental permits, mineral rights contracts, and other legally binding agreements. This may include the mineral rights estate(s), government agencies, surface estate(s), tribal governments, and nearby communities.

2. Labor and Safety: The project developer must attest that the project is in material compliance with all applicable laws, including labor or safety laws. See Section 3.5 Regulatory Compliance for further information. Furthermore, all construction, maintenance, and operations of project related equipment (generators, rigs, flares, pumps, meters, etc.) must follow manufacturer guidance to avoid injury while working with methane and other volatile gases.

3. Dispute Resolution: The Reserve holds a 30-day public comment period on all listed projects prior to registration and has an ongoing dispute resolution process. See the Reserve Offset Program Manual and website for further information on programmatic and project specific public consultation and dispute resolution processes. Projects that receive material complaints will not be registered until a satisfactory dispute resolution plan has been approved. The operator(s) and/or the project developer must attest that

they have title to the entire project boundary, including all facilities directly related to the carbon project.

The environmental safeguards requirements include:

1. Air and Water Quality: The project developer must attest that the project is in material compliance with all applicable laws, including environmental regulations (e.g., air and water quality and groundwater testing).

2. Mitigation of Pollutants: Projects must be designed and implemented to mitigate potential releases of pollutants that may cause degradation of the quality of soil, air, surface and groundwater, and project developers must acquire the appropriate local permits prior to P&A to prevent violation of all applicable laws.

3. Effective Plugging: Project wells must be plugged with surface remediation according to all applicable federal, state, local, and tribal regulations to restore environmental integrity, prevent contamination of soil and groundwater, and protect public health. See Section 3.2 Project Start Date, Section 6 Monitoring, and Section 7.3 Record Keeping for more information.

4 The GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that must be assessed by project developers in order to determine the net change in emissions caused by an early decommissioning project.

The fugitive emissions after a well is plugged are not considered in the GHG assessment boundary when quantifying project emissions because the resulting emissions are de minimis.[26] However, fugitive emissions must be monitored periodically for the purposes of ensuring integrity of the cement plug. See Section 6 for the monitoring requirements for post-plugging fugitive emissions.

Figure 4.1 illustrates all relevant GHG SSRs associated with early decommissioning of marginal oil and gas wells project activities and delineates the GHG Assessment Boundary.

Table 4.1 provides greater detail on each SSR (Source, Sink, or Reservoir) and justification for the inclusion or exclusion of certain SSRs and gases from the GHG Assessment Boundary.

[26] The EPA GHG Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2022 (2024) estimates the emissions of plugged abandoned wells to be an average of less than 1 kgCH4 per well per year.

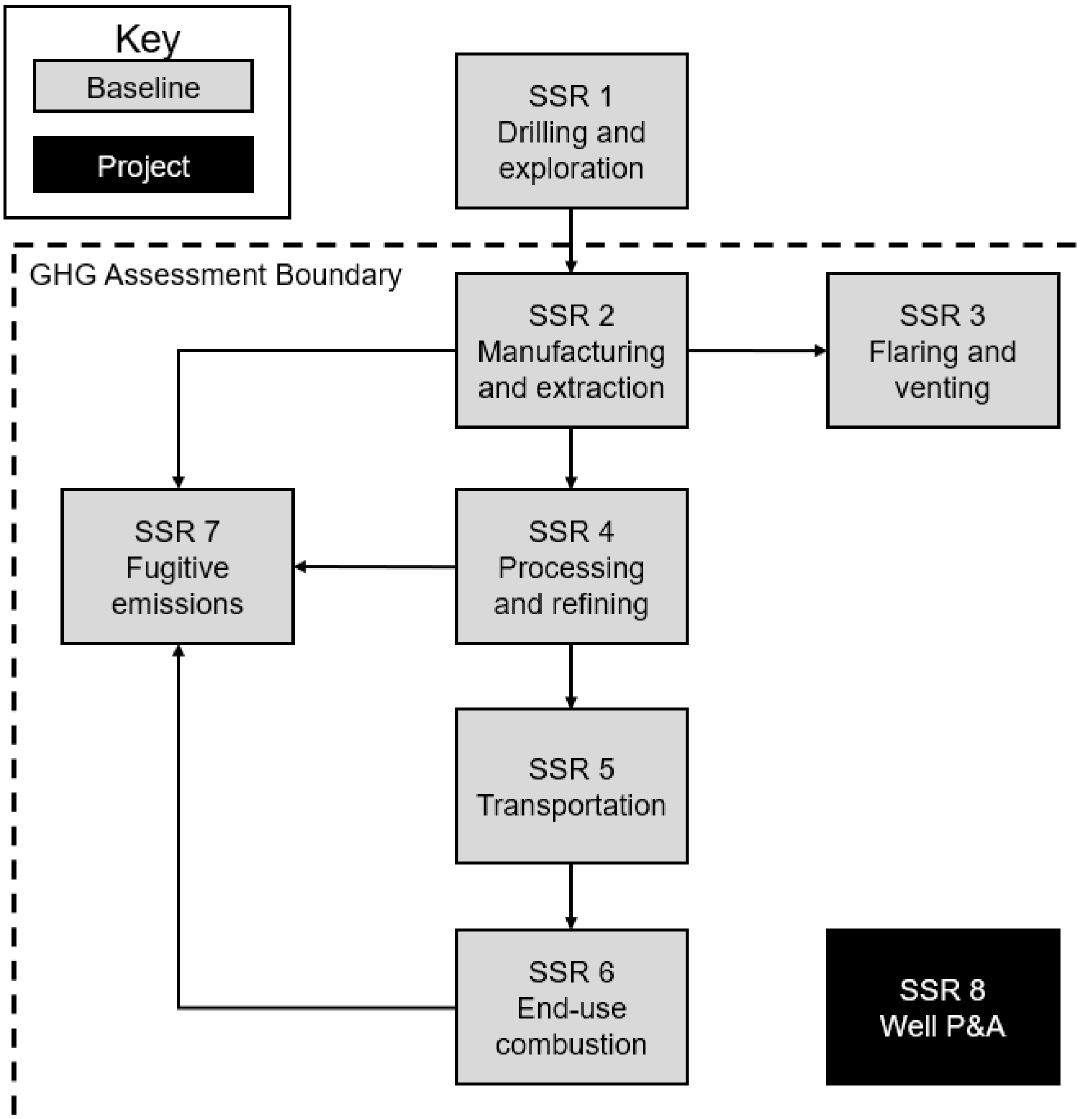

Figure 4.1. General illustration of the GHG Assessment Boundary

Table 4.1. Description of all Sources, Sinks, and Reservoirs

SSR	Source Description	Gas	Included (I) or Excluded (E)	Baseline (B) or Project (P)	Justification/Explanation
1	Upstream emissions associated with oil and gas exploration	CO_2	E	B	Excluded, as the emissions would occur regardless of whether the project activity is undertaken
		CH_4			
		N_2O			
2	Process emissions for the manufacturing and extraction of oil and natural gas	CO_2	I	B	Included in the project boundaries and is considered a significant source of emissions
		CH_4			
		N_2O			
3	Intentional excess gas flaring and venting associated with ongoing production of oil and natural gas	CO_2	I	B	GHG emissions resulting from flaring, which serve as preventive or corrective safety measures at a facility
		CH_4			
		N_2O			
4	Midstream emissions associated with processing and refining	CO_2	I	B	GHG emissions resulting from the processing of hydrocarbons at refineries or similar facilities
		CH_4			
		N_2O			
5	Emissions associated with gathering, storage, and transportation	CO_2	I	B	GHG emissions resulting from the combustion of fossil fuels for gathering, storage, and transportation, extending from the gate to the end-user, are identified as relevant source of emissions
		CH_4			
		N_2O			
6	End-use emissions associated with the consumption of fuel	CO_2	I	B	Considered to be a significant source of emissions
		CH_4			
		N_2O			

SSR	Source Description	Gas	Included (I) or Excluded (E)	Baseline (B) or Project (P)	Justification/Explanation
7	Fugitive emissions associated with upstream, midstream and logistics	CO_2	I	B	Emissions occurring at any stage of the oil and gas production process
		CH_4			
		N_2O	E		Negligible GHG in fugitive emissions
8	Emissions associated with plugging the project well	CO_2	I	P	Fossil fuel emissions used to power equipment and embodied emissions from the cement to plug the well are included in the project emissions.
		CH_4			
		N_2O			

5 Quantifying GHG Emission Reductions

GHG emission reductions from a marginal well project are quantified by comparing actual project emissions to the calculated baseline emissions. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the project, adjusted for permanence, leakage, and uncertainty. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1). Figure 1 provides an overview of how the remainder of equations in this section relate to Equation 5.1.

GHG emission reductions must be quantified and verified on at least an annual basis. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are periodically quantified and verified is called the "reporting period." A project that can achieve legal permanence, as defined in Section 5.1.1, may choose to forgo annual verifications given legal permanence eliminates this non-permanence risk. For these projects, an issuance of the emission reduction credits attributed to the full economic limit of the well is available following the initial project verification (see approach 2 in Section 5.1.1 Adjusted Economic Reserves).

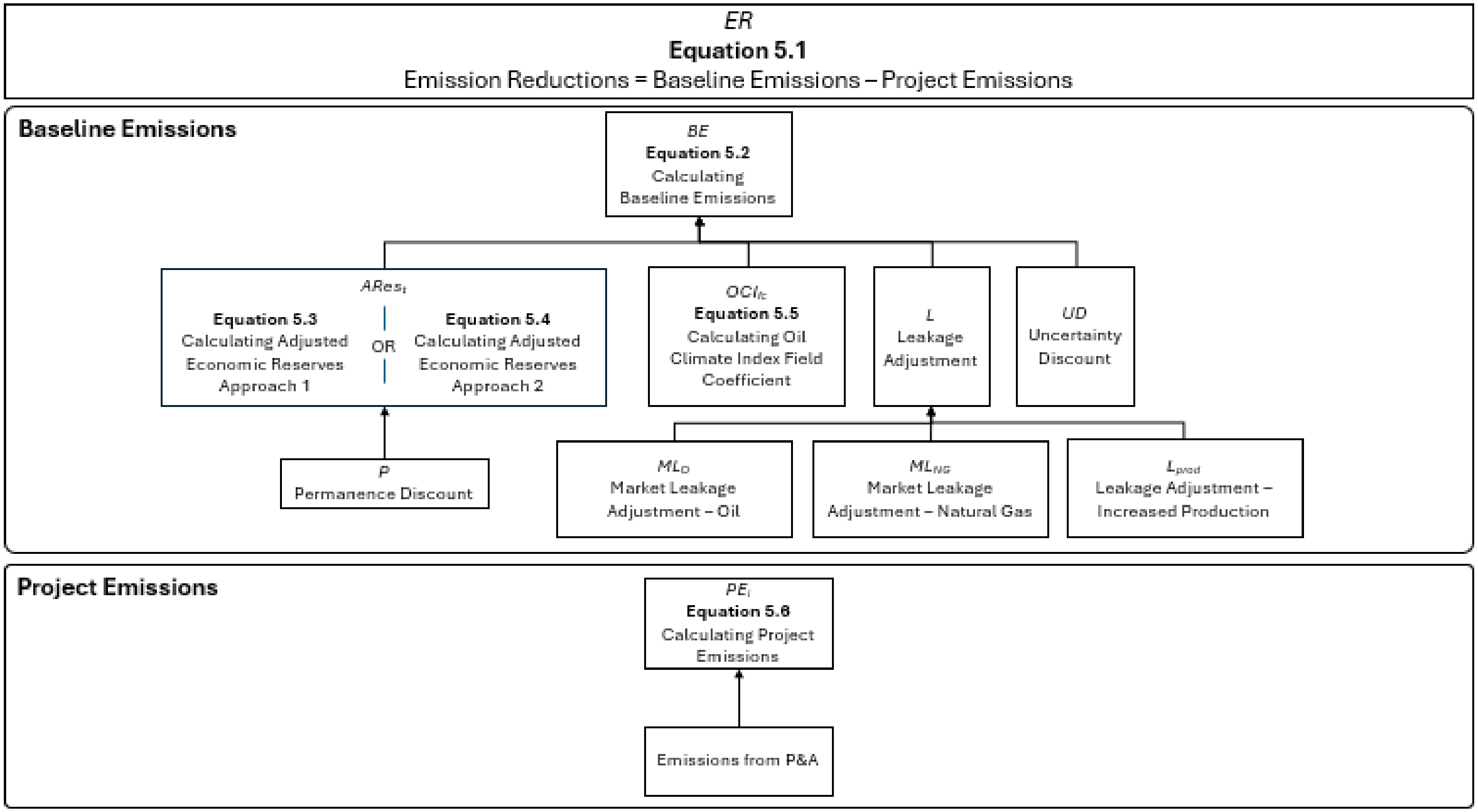

Figure 5.1. Organizational Chart for Equations in Section 5

Equation 5.1. Calculating GHG Emission Reductions

$$ER = BE - PE_i - LE_t$$

Where,			Units
ER_t	=	Emission reductions for reporting period *t*	tCO_2e
BE	=	Baseline emissions for reporting period *t* (calculated in Equation 5.2)	tCO_2e
PE_i	=	Project emissions, only deducted during the initial reporting period (see Section 5.2)	tCO_2e
L_t	=	Leakage adjustment for reporting period *t*	tCO_2e

5.1 Quantifying Baseline Emissions

Total baseline emissions for the reporting period are estimated by calculating the emissions from all relevant baseline SSRs that are included in the GHG Assessment Boundary (as indicated in Table 4.1).

Equation 5.2. Calculating Baseline Emissions

$$BE = ARes_t \times OCI_{fc} \times UD_t$$

Where,			Units
BE	=	Baseline emissions for the reporting period	tCO_2e
$ARes_t$	=	Adjusted economic reserves for reporting period *t,* adjusted for non-permanence risk (see Section 5.1.1 and Appendix D)	BOE
OCI_{fc}	=	Oil Climate Index Field Coefficient (see Section 5.1.2)	tCO_2e/BOE
UD_t	=	Uncertainty discount (see Section 5.1.2 and Appendix D.3.2)	% (as decimal)

5.1.1 Adjusted Economic Reserves

The Protocol limits crediting to the economic reserves that would have been produced during the crediting period or the length of the economic life, whichever is less. Due to the risk of impermanence, projects may not be eligible to receive crediting for the economic reserves that would have been produced outside of the crediting period. However, if a project can demonstrate physical and legal permanence, then the project may be eligible to receive credits attributed to all economic reserves after the initial verification, regardless of whether the economic life exceeds the crediting period.

The adjusted economic reserves ($ARes_t$) refers to the economic reserves (as identified by the PPEF evaluation), adjusted for impermanence risk. Projects assessing $ARes_t$ produced only during the crediting period must be use Approach 1. All projects using Approach 1 must also assess the risk of sequestered economic reserves to be recovered by another well, referred to as reservoir communication (see Section 3.4.1.2 and Appendix D), and apply a permanence discount (*P*), as described below. Projects able to demonstrate physical and legal permanence must use Approach 2 determine $ARes_t$.

Equation 5.3 must be used to calculate the economic reserves attributable to each reporting period, adjusted for impermanence risk, under Approach 1.

Equation 5.3. Calculating Adjusted Economic Reserves: Approach 1

$$ARes_t = Res_t \times (1 - P)$$

Where,			Units
$ARes_t$	=	Adjusted economic reserves for reporting period t (adjusted for non-permanence risk)	BOE
Res_t	=	Economic Reserves for reporting period t (provided by the PPEF)	BOE
P	=	Permanence discount, either 0, 5, or 20 percent, as determined per Appendix D	% (as decimal)

All projects must assess the risk of impermanence due to reservoir communication (see Section 3.4.1.2 and Appendix D). If a project can demonstrate to a reasonable level of certainty that the reserves will not be accessed by another well, then no adjustments for permanence are required. Conversely, if a project is unable to demonstrate to a reasonable level of certainty that the reserves will not be accessed by another well, then either a 5% or 20% discount must be applied.

Approach 2 allows for crediting of all economic reserves for a well with a projected productive life that exceeds the crediting period for the project, provided additional permanence requirements are met. To demonstrate legal permanence, the project must either demonstrate jurisdictional or local permanence:

- Jurisdictional permanence: cities, counties, or states where it is illegal or otherwise against regulation to drill new oil and gas wells or reopen plugged wells to access hydrocarbons. Project developers must provide proof of such regulation, law, or legally binding mandate during verification.
- Local permanence: legal mechanisms that restrict mineral and/or surface exploitation. These mechanisms must clearly prevent new drilling or reopening of project wells that might threated sequestered reserves. Types of instruments and contracts that may indicate local permanence include:
  - Conservation Easements: Legal documents that prohibit drilling, mining, or other forms of mineral extraction across the project area.
  - Property Use Agreements: Contracts restricting the extraction of oil and gas executed by mineral and/or surface rights holders.

If the verification body cannot reach a reasonable level of assurance, the project cannot use Approach 2 for baseline emissions calculations.

Equation 5.4. Calculating Adjusted Economic Reserves: Approach 2

$$ARes = TRes \times (1 - P)$$

Where,			Units
ARes	=	Adjusted economic reserves (adjusted for non-permanence risk)	BOE
TRes	=	Total economic reserves throughout the remaining economic life of the well (provided by the PPEF)	BOE
P	=	Permanence Discount	% (as decimal)

If a project can achieve legal permanence under approach 2, the risk of the well being reopened after it is plugged has been eliminated and the project may be issued credits attributed to emission reductions for the total economic reserves.

5.1.2 Uncertainty Discount

The uncertainty discount accounts for the uncertainty associated with the ongoing research on and the need for more comprehensive data related to the migration of reserves to adjacent wells and the long-term effectiveness of well plugs. The uncertainty discount may be periodically updated in response to emerging research findings and the availability of new data.

Projects that require a qualitative permanence review (see Section 3.4.1.2 and Appendix D.3.2) and are determined to have low or medium data conclusiveness must apply an uncertainty discount of 5% or 1%, respectively, in Equation 5.2. The PPEF will determine whether a project has low, medium, or high data conclusiveness.

5.1.3 Oil Climate Index Field Coefficient

The Oil Climate Index Plus (OCI^+)[27] is a comprehensive tool that employs a hybrid approach, combining bottom-up systems analysis with top-down measurements, to quantify GHG emissions from oil and gas production, processing, refining, shipping, and end uses. This bottom-up approach involves detailed analysis at each stage of production and processing, while top-down measurements provide overarching data for validation and broader context. For more detailed information on the OCI^+ methodology and directions on how to use the OCI+ tool, refer to Appendix C.

Equation 5.5 is used to calculate the Oil Climate Index Field Co-efficient (OCI_{fc}) using the OCI+ tool. OCI_{fc} represents the emission intensity for each barrel of oil and gas produced by the project well in terms of tCO_2e/BOE. When determining the emission intensity of oil and gas production (EM_{prod}) from the OCI+ tool, the emissions from drilling, development and exploration should be excluded, as the source is considered outside of the GHG assessment boundary.

Equation 5.5. Calculating Oil Climate Index Field Coefficient

$$OCI_{fc} = \left(EM_{prod} + EM_{ref} + EM_{gst} + EM_{end}\right) \times 1000$$

Where,			Units
OCI_{fc}	=	Oil Climate Index field coefficient. See Appendix C.	tCO_2e/BOE

[27] For more detailed information on the OCI^+ methodology, case studies, and data analysis, please refer to Appendix C.

EM_{prod}	=	Emissions intensity of oil and gas production, excluding drilling, development, and exploration emissions (SSR 2, 3, and 7)	$kgCO_2e/BOE$
EM_{ref}	=	Emissions intensity of oil and gas refining and petrochemical processing (SSR 4 and 7)	$kgCO_2e/BOE$
EM_{gst}	=	Emissions intensity of oil and gas gathering, storage, and transportation (SSR 5)	$kgCO_2e/BOE$
EM_{end}	=	Emissions intensity of oil and gas end uses (SSR 6 and 7)	$kgCO_2e/BOE$
1000	=	Unit conversion of kg to metric tonne	tonne/kg

5.2 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the GHG assessment boundary as a result of the project activity. To conservatively estimate the project emissions, the emissions associated with the P&A process must be quantified. They are considered a one-time emission source occurring on the project start date. Thus, project emissions are only reported and subtracted from the baseline emissions during the initial reporting period.

The main sources of emissions for the project activity are the fossil fuel emissions associated with the equipment used to complete P&A activities and the embodied emissions of the cement plug.[28] The fossil fuel emissions are determined by multiplying the quantity of the fossil fuels by the fuel specific emission factor. The embodied emissions of the cement plug are the cradle-to-gate emissions as a result of producing one tonne of cement. The emission intensity of the cement (in terms of kgCO2e per tonne of cement) shall be determined by using the appropriate Environmental Product Declaration (EPD). Projects should use the EPD from the manufacturer,[29] if available. However, in instances where the site-specific EPD is unavailable, then the project may utilize the industry average EPD.[30]

Equation 5.6. Calculating Project Emissions

$$PE_i = \frac{\sum_j FF_j \times EF_{FF,j}}{1000} + (Q_c \times EI_c)$$

Where,			Units
PE_i	=	Project emissions, equal to the emissions during P&A activities, to be accounted for in the initial reporting period only	tCO_2e
FF_j	=	Total quantity of fossil fuel consumed in all plugging activities, by fuel type *j*	volume of fossil fuel

[28] Common cements used for plugging include API oil well cements (API 10) Class A, B, C, G, and H, as well as regionally manufactured industrial ASTM cements (ASTM C150 and C195) including Type 1, 3, 1L, and 3L.
[29] Per governing standards, EPDs are only valid for up to five years.
[30] The American Cement Association (ACA) publishes industry average EPDs for portland cement, portland-limestone cement, blended cements, and masonry cement.

EF	=	Fuel specific emission factor[31]	$kgCO_2$ / volume fossil fuel
1000	=	Unit conversion of kg to metric tonnes	$kgCO_2/tCO_2$
Q_c	=	Quantity of cement, *c,* used to plug the well	tonne
EI_c	=	Emission intensity of cement, *c,* as defined in the EPD[32]	kgCO2e / tonne cement

5.3 Secondary Effects

A leakage adjustment must be applied in Equation 5.2 to account for the secondary effects from the early plugging of the marginal well. Secondary effects are two-fold: leakage from increased production prior to P&A, and market leakage due to shifting oil and gas supplies as other oil and/or gas producers increase their production to make up for the loss of supply coming from project well. Project developers must determine the appropriate leakage adjustments according to Sections 5.1.4.1 through 5.1.4.3 and calculate the total leakage adjustment in Equation 5.6 below.

Equation 5.7. Calculating Leakage Adjustment

$$L_t = PL_{inc,i} + ML$$

Where,			Units
L_t	=	Total leakage adjustment for reporting period, *t*	% (as decimal)
$PL_{inc,i}$	=	Leakage adjustment for increased production prior to start date, only applicable during the initial reporting period (see Equation 5.7)	% (as decimal)
ML	=	Market leakage adjustment	% (as decimal)

5.3.1 Leakage from Increased Production

Unintended secondary effects, i.e., carbon leakage, may occur if an oil and gas well increases production of hydrocarbons above historic rates prior to the project start date. Projects that increase production above the average daily production rate over a three-year lookback period after the contract effective date with the PPEF and before the project start date must account for the increased emissions. This leakage adjustment only needs to be applied in the initial reporting period since it is a one-time emissions source.

Project developers must determine an average production rate (BOE/day) over the previous three years prior to the project start date, as well as the average production rate (BOE/day) between the contract effective date with the PPEF and the project start date. If production decreased or remained unchanged, then no leakage adjustment for increased production is

[31] 40 CFR Part 98 Subpart C Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel.
[32] Projects must use the global warming potential, GWP 100 value in the EPD.

required. However, if production increased, then the project must calculate the leakage adjustment in Equation 5.7 below.

Equation 5.8. Calculating Leakage Adjustment from Increased Production

$$PL_{inc,i} = \left(\frac{Q_{OG,new} - Q_{OG,BL}}{Q_{OG,BL}}\right)$$

Where,

			Units
$PL_{inc,i}$	=	Leakage adjustment for increased production prior to start date, only applicable during the initial reporting period	% (as decimal)
$Q_{OG,new}$	=	Average quantity of oil and gas produced after the contract effective date and before plugging.	BOE/day
$Q_{OG,BL}$	=	Average quantity of oil and gas produced in the three-year lookback period	BOE/day

5.3.2 Market Leakage Adjustment

[DRAFTING IN PROGRESS] Market leakage refers to the risk that emission reductions achieved by a project are offset by an increase in emissions outside of the protocol boundary as a result of the market compensating for the oil and/or gas supply lost from a project well. Refer to Appendix A for the leakage analysis.

The project's market leakage rate is a function of the rate at which the market will supplement the oil and gas sequestered by the project well, as well as the GHG emission intensity of the supplemental source. The protocol applies a single, 56% market leakage adjustment for both oil and natural gas wells. However, natural gas wells require an additional adjustment to account for the difference in the GHG intensity of the alternative fuels.

Equation 5.9. Calculating Market Leakage Adjustment

[Placeholder Table]

Where, Units

5.3.2.1 Oil Market Leakage

[DRAFTING IN PROGRESS] The protocol applies a single, 56% market leakage adjustment for all oil well projects in the US. No additional adjustments are required to account for GHG emission intensities.

5.3.2.2 Natural Gas Market Leakage

[DRAFTING IN PROGRESS]
Proposal: To account for the GHG intensity, we will quantify the combined GHG intensity of replacement energy sources (weighted by the percent grid electricity produced), plus the natural gas not used for electricity purposes. Projects will select the value based on the location of the well. Introductory research is provided in Appendix A.

6 Project Monitoring

[DRAFTING IN PROGRESS] The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 will be collected and recorded. The Monitoring Plan will serve as the basis for verifiers to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record keeping is ongoing at the project site.

At a minimum, the Monitoring Plan shall include the frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements); the role of individuals performing each specific activity; and a detailed project description. The monitoring plan shall include the following information:

- Project description
- Photographs of the well(s) and tanks or surface equipment located at the well(s) site
- Plugging plan or permit submitted to pertinent natural resources regulator
- Economic Reserves Report drafted by PPEF
- Well(s) identifier: API, UWI
- Surface location of the well(s)
- Procedures to meet the annual reservoir communication monitoring requirements
- Documentation that the operator and plugger have rights to access and plug well
- Professional Petroleum Engineering Firm credentials
- Copy of plugging record given by the appropriate regulatory agency
- Data to be monitored and collected
- Overview of data collection procedures
- Procedures for monitoring cement plug integrity
- Frequency of the monitoring
- Data archiving, and
- Organization and responsibilities of the parties involved in the above tasks

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the legal requirement test (Section 3.4.2).

6.1 Monitoring Requirements

All projects are required to monitor the following activities:

1. Plugging and abandonment processes
2. Integrity of the plug over time
3. Reservoir communication
4. *Other requirements?*

6.1.1 Plugging and Abandonment

[DRAFTING IN PROGRESS] P&A requirements are established by federal and state agencies. The EPA has established comprehensive guidelines for well plugging, emphasizing the use of durable materials like cement to create effective seals, and mandate pressure testing to ensure the integrity of the plug to prevent fluid migration. The Bureau of Land Management[33]

[33] 43 CFR 3160

establishes minimum requirements for onshore oil and gas wells on federal and Native American Lands, and state agencies oversee the requirements for wells on private land.

At a minimum, project developers must ensure that the project meets the applicable P&A requirements of federal, state, local, and tribal requirements. The monitoring plan must include procedures that the project developer will follow to ascertain and demonstrate that the project will adhere to such requirements.

The project's monitoring report will provide relevant information and a detailed log of the procedures that were followed during the P&A process, which should include, at a minimum,

1. Name of the agency with legal authority over the P&A, including agency representative contact information
2. Name of the entity plugging the well, including primary contact information
3. Type of cement used, including ASTM standard and manufacturer
4. Photograph of the well prior to plugging activities commence
5. Date and time P&A activities started
6. Date and time of each step within the P&A process (e.g., removal of bore casing and other equipment, placement of cement plugs, excavation, and reclamation activities)
7. Date and time P&A activities were completed
8. Date the well change in status was submitted to the applicable agency
9. Date the state approved and has certified the well as P&A
10. *Other information?*

6.1.2 Integrity of Cement Plug Over Time

[DRAFTING IN PROGRESS] Under the EPA's Class VI regulations, which govern wells used for geologic sequestration of CO_2, there are strict requirements for post-injection site care. This includes continuous monitoring and testing to detect any potential leaks, ensuring that the plugged wells do not pose a threat to underground sources of drinking water.

Studies have shown that the risk of leaks from properly plugged wells is minimal. For instance, research indicates that when cement plugs are correctly placed and maintained, they effectively prevent fluid migration. The EPA's guidelines also highlight that the use of mechanical plugs in conjunction with cement can enhance the sealing capability of the plug.

Furthermore, the EPA's Class VI regulations require that a well cannot be permanently closed until data demonstrates that there is no danger to underground sources of drinking water. This ensures that any potential issues are identified and addressed before the well is considered safely plugged.
While no system is entirely fail-proof, the combination of modern plugging techniques, rigorous testing, and ongoing monitoring significantly mitigates the risk of leaks. The EPA's emphasis on post-injection site care, including pressure testing and monitoring, ensures that any potential issues are detected early and remedied promptly. When wells are plugged following current EPA regulations and best practices, the likelihood of leaks is substantially reduced.

The project must conduct direct emissions source testing every 5 years, at a minimum, beginning from the project start date. For example, if the project has a start date of 1/1/2025 then measurements must be taken no later than 12/31/2029 and 12/31/2034 during the initial crediting period. Emission source testing must be conducted by a third-party technician or service provider at each leak point of the well. The third-party technician or service provider may choose the appropriate source measurement method outlined in the National Energy

Technology Laboratory Methane Measurement Guidelines for Marginal Conventional Wells. The minimum detection limit must be less than 100grams/hour.[34] All devices used in conformance with and maintained according to manufacturer recommendations. All leak points must be included in the project's monitoring plan, as well as in the procedures for meeting direct methane emission monitoring requirements.

Projects may be subject to more frequent source testing in situations where there was an extreme weather event (e.g. earthquakes, tornadoes) within a reasonable distance from the project site. Procedures for ensuring well integrity as it pertains to extreme weather must be outlined in the monitoring plan.

If an emissions leak is detected, then the emissions must be compensated during the verification for the subsequent reporting period. To determine the quantity of emissions attributed to well integrity, the project developer must take the rate of the emissions multiplied by the duration since the last leak testing date.

6.1.3 Reservoir Communication

Every reporting period, the project developer must determine whether a new well has been drilled and completed within the AoR (as established by the PPEF), and whether existing wells undergo operational changes (e.g., idle to active or vice versa). If there were no changes since the previous verification, then no changes to the permanence discount is required. However, if a new well is identified or there is a change in operational status with an existing well, then the project developer must re-assess the reservoir communication in accordance with Appendix D. Thus, a new permanence discount may be applied.

6.2 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

[34] In line with National Energy Technical Laboratory, US DOE, Methane Measurement Guidelines for Marginal Conventional Wells, Version 1, April 2024.

Table 6.1. Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
General Project Parameters						
	Regulations	Project developer attestation of compliance with regulatory requirements relating to the project		n/a	Each verification	Information used to: 1) To demonstrate ability to meet the legal requirement test – where regulation would require the well to be plugged and abandoned. 2) To demonstrate compliance with associated environmental rules, e.g., criteria pollutant emission standards, health and safety, groundwater, etc.
5.1	*ER*	Emission reductions for the reporting period	tCO_2e	C	Each reporting period	
Baseline Calculation Parameters						
5.1, 5.2	*BE*	Baseline emissions for the reporting period	tCO_2e	C	Each reporting period	
5.2, 5.3	$ARes_t$	Adjusted economic reserves for the reporting period, adjusted for permanence risk	BOE	C	Each reporting period	
5.2	OCI_{fc}	Oil Climate Index Field Coefficient	tCO_2e/BOE	C	Each reporting period	

Eq. #	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
5.2	UD_t	Uncertainty discount	% (as decimal)	R	Every reporting period	Uncertainty discount may be adjusted as more information becomes available.
	leakage					
5.3, 5.4	Res_t	Economic reserves for the reporting period	BOE	R	Every reporting period	Value is provided by the PPEF
5.3, 5.4	P	Permanence discount	% (as decimal)	R	Every reporting period	Permanence discount may be adjusted every reporting period depending on the
5.4	$LRes$	Limited economic reserves	BOE	R	Once at the beginning of the project	Limited to 20 years post-plugging. Value is provided by the PPEF and represents 20 years' worth of economic reserves.
5.4	$TRes$	Total economic reserves throughout the remaining economic life of the well	BOE	R	Once at the beginning of the project	Value is provided by the PPEF.
5.5	EM_{prod}	Emission intensity of oil and gas production	kgCO2e/BOE	R	Every reporting period	Value is obtained from the OCI+ Tool. Emissions should exclude drilling, development, and exploration emissions since they are outside of the project boundary.

Eq. #	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
5.5	EM_{ref}	Emission intensity of oil and gas refining and petrochemical processing	$kgCO_2e/BOE$	R	Every reporting period	Value is obtained from the OCI+ Tool.
5.5	EM_{gst}	Emission intensity of oil and gas gathering, storage, and transportation	$kgCO_2e/BOE$	R	Every reporting period	Value is obtained from the OCI+ Tool.
5.5	EM_{prod}	Emission intensity of oil and gas production	$kgCO_2e/BOE$	R	Every reporting period	Value is obtained from the OCI+ Tool.
Project Calculation Parameters						
5.6	P_i	Project emissions	tCO_2e	C	Once during initial reporting period	Represents the emissions associated with plugging and abandonment emissions. Accounts for the fossil fuel emissions from plugging equipment and the embodied emissions of the cement plug material(s).
5.6	FF_j	Total quantity of fossil fuel emissions consumed in all plugging activities	Volume of fossil fuel	O	Once during initial reporting period	Quantity of fossil fuels used to power plugging equipment are supplied by the plugging company and obtained from invoices.
5.6	$EF_{FF,j}$	Fuel specific emission factor	$kgCO_2$ / volume fossil fuel	R	Once during initial reporting period	Fuel-specific emission factors are obtained from 40 CFR Part 98 Subpart C Table C-1: Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

Eq. #	Parameter	Description	Data Unit	Calculated (c) Measured (m) Reference (r) Operating Records (o)	Measurement Frequency	Comment
5.6	Q_c	Quantity of cement, c	Tonne	O	Once during initial reporting period	Quantity of cement used to plug the well are supplied by the plugging company and obtained from invoices and other documentation
5.6	EI_c	Emission intensity of cement, c	kgCO2e / tonne cement	R	Once during initial reporting period	Shall be determined by using the appropriate Environmental Product Declaration (EPD), either from the manufacturer or industry average EPD.

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure among project developers. Project developers must submit verified emission reduction reports to the Reserve for every reporting period.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to list an Early Plugging of Marginal Oil and Gas Wells project:

- Project Submittal form
- Project Diagram

Project developers must provide the following documentation each verification period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Opinion
- List of Findings (not public)
- Project Data Report
- Environmental and Social Safeguards form
- Sustainable Development Goals (SDG) Tool
- Professional Petroleum Engineering Firm Conflict of Interest and Qualifications Assessment Form (not public)
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form

At a minimum, the above project documentation will be available to the public via the Reserve's online registry, unless otherwise noted above. Further disclosure and other documentation may be made available on a voluntary basis through the Reserve. Project submittal forms can be found on the Protocol webpage.

7.1.1 Project Data Report

A Project Data Report (PDR) is a required document for reporting information about a project. The document must be submitted for every reporting period. A PDR template has been prepared by the Reserve and is available on the Reserve's website. The template is arranged to assist in ensuring that all requirements of the protocol are addressed. PDRs are intended to serve as the main project document that thoroughly describes how the project meets eligibility requirements, discusses the quantification methodologies utilized to generate project estimates, and outlines how the project complies with terms for additionality. PDRs must be of professional quality and free of incorrect citations, missing pages, incorrect project references, etc.

7.1.2 Project Map

Project developers must provide a project map depicting the project well location(s) along with the following:

- Longitude and latitude coordinates
- Governing jurisdictions

- Public and private roads
- Geological reservoir boundary
- Mineral rights boundary
- Surface rights boundary

7.2 Joint Project Verification

When a protocol allows for multiple projects at a single site or facility, project developers have the option to hire a single verification body to verify multiple projects at a facility through a "joint project verification." This may provide economies of scale for the project verifications and improve the efficiency of the verification process. The protocol allows for multiple wells to be reported under a single project, given certain conditions, however, it is not required. Only projects that have wells with the same ownership and located in the same geological reservoir are eligible for joint project verification.

Under joint project verification, each project, as defined by the protocol, is submitted for listing, listed, and registered separately in the Reserve system. Furthermore, each project requires its own separate verification process and Verification Opinion (i.e., each project is assessed by the verification body separately as if it were the only project at the site or facility). However, all projects may be verified together by a single site visit. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol 7 years after the last verification of the crediting period. This information will not be publicly available but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of the emission reductions, including OCI+ Tool inputs
- Copies of all permits, Notices of Violations (NOVs), and any relevant administrative or legal consent orders dating back at least 3 years prior to the project start date
- Executed Attestation of Title, Attestation of Regulatory Compliance, and Attestation of Voluntary Implementation forms
- Results of CO_2e reduction calculations
- Initial and annual verification records and results
- Documentation confirming notification of applicable parties, including state agencies, tribal communities, mineral and surface estate, etc.
- Results of ongoing permanence monitoring
- Copies of PPEF report(s) for the economic reserves, economic limit, data conclusiveness, and percent recoverable reserves
- Records required for evaluating PPEF conflict of interest and qualifications
- Documentation of ongoing monitoring for cement well plug integrity, including records pertaining to extreme weather events and procedures to document potential impact to the project well.
- *Other information?*

7.4 Reporting Period and Verification Cycle

7.4.1 Reporting Periods

The reporting period is the length of time over which GHG emission reductions from project activities are quantified. Project developers must report project activity data results for each reporting period. A reporting period may not exceed 12 months in length, except for the initial reporting period, which may cover up to 24 months. The project's initial reporting period begins on the project start date. The Reserve accepts verified emission reduction reports on a sub-annual basis, should the project developer choose to have sub-annual reporting period and verification schedule (e.g., monthly, quarterly, or semi-annually). Reporting periods must be contiguous; there may be no time gaps in reporting during the crediting period of a project once the first reporting period has commenced.

7.4.2 Verification Periods

The verification period is the length of time over which GHG emission reductions from project activities are verified. The initial verification period for a marginal oil and gas project is limited to one reporting period of up to 24 months of data. Subsequent verification periods may cover up to two reporting periods, with a maximum of 24 months of data (i.e., 12 months of data per reporting period). CRTs will not be issued for reporting periods that have not been verified. For any reporting period that ends prior to the end of the verification period (i.e., year 1 of a 2-year verification period), an interim monitoring report must be submitted to the Reserve no later than six months following the end of the relevant reporting period. The interim monitoring report shall contain a summary of emission reductions, description of regulatory compliance status, annual permanence monitoring, and fugitive emissions monitoring activities, if conducted.

To meet the verification deadline, the project developer must have the required verification documentation (See Section 7.1) submitted within 12 months of the end of the verification period. The end of any verification period must correspond to the end of the reporting period.

7.4.3 Verification Site Visit Schedule

A site visit must occur during the initial verification, which will occur after the completion of all P&A activities. The Reserve retains the discretion to require additional site visits or verifications if warranted due to material changes, deviations, or project-specific considerations.

8 Verification Guidance

[DRAFTING IN PROGRESS] This section provides verification bodies with guidance on verifying GHG emission reductions associated with the project activity. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities specifically related to marginal oil and gas wells plugging projects. Verification guidance provided below must be applied to each individual well, such that, if a project includes multiple wells, each well must be assessed individually against the protocol. Sampling methods should be considered relative to the individual well rather than all wells within a given project.

Verification bodies trained to verify these projects must be familiar with the following documents:

- Reserve Offset Program Manual
- Reserve Verification Program Manual
- Reserve Early Plugging of Marginal Oil and Gas Wells Protocol (this document)

The Reserve Offset Program Manual, Verification Program Manual, and protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

Only ISO-accredited verification bodies trained by the Reserve are eligible to verify project reports. Verification bodies approved under other protocol types may be permitted to verify marginal oil and gas wells plugging projects.[35] Information about verification body accreditation and Reserve project verification training can be found on the Reserve website at http://www.climateactionreserve.org/how/verification/.

8.1 Standard of Verification

The Reserve's standard of verification for marginal oil and gas wells plugging projects is this Protocol (this document), the Reserve Offset Program Manual, and the Verification Program Manual. To verify a marginal oil and gas well plugging project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Sections 2 through 4 of this protocol. Sections 2 through 4 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.2 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.3 Verifying Project Eligibility

Verification bodies must affirm a project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for these projects. This table does not

[35] See section 3.4.2 of the Verification Program Manual.

present all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria for a Marginal Oil and Gas Wells Project

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	For 12 months following the Effective Date of this protocol, a pre-existing project with a start date on or after methodology acceptance may be submitted for listing; after this 12-month period, projects must be submitted for listing within 12 months of the project start date.	Once during initial verification
Location	United States and U.S. territories and tribal areas	Once during initial verification
Performance Standard Test	Only proved reserves (P1) are eligible and evaluated by the PPEF. The well must be economically viable as of the project start date.	Once during initial verification of each crediting period
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures for ascertaining and demonstrating that the project passes the legal requirement test	Every verification
Regulatory Compliance	Signed Attestation of Regulatory Compliance form and disclosure of all non-compliance events to verifier; project must be in material compliance with all applicable laws.	Every verification

8.4 Core Verification Activities

The Protocol provides explicit requirements and guidance for quantifying the GHG reductions associated with the project. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies. They are summarized below in the context of an early plugging of marginal oil and gas wells project, but verification bodies must also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emission sources, sinks, and reservoirs (SSRs)
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a marginal oil and gas wells project.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the project uses to gather data and calculate baseline and project emissions.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This

involves site visits to the project site (or sites if the project includes multiple wells) to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates emissions data for each well reporting under the project with data reported on the OCI+ tool.

8.5 Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a marginal oil and gas wells project. The tables include references to the section in the protocol where requirements are further specified. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide sufficiently prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to marginal oil and gas wells projects that must be addressed during verification.

8.5.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for marginal oil and gas wells projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or subset of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2.2	Verify that the project meets the definition of a marginal oil and gas wells project	No
2.3	Verify ownership of the reductions by reviewing contracts and operational records. Confirm that the Attestation of Title was submitted	No
3.2	Verify project start date	No
3.2	Verify accuracy of project start date based on government documents	Yes
3.2	Verify that the project has documented and implemented a Monitoring Plan	No
3.3	Verify that project is within its 10-year crediting period	No
3.4.1	Verify that the project meets the performance standard test, including: ▪ Confirm the PPEF report provides P1 reserves only ▪ Confirm production is reported as two separate 10-year production rates. ▪ Confirming the PPEF report states that the well(s) has not reached its economic limit ▪ Confirm the PPEF report has been submitted to the Reserve	No
3.4.1.2	Confirm the PPEF report provides a reservoir communication assessment, permanence discount, and data uncertainty discount that aligns with the requirements of the protocol.	No

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
3.4.3.2	Confirm the project has not received funding for voluntary decommissioning and plugging	Yes
3.4.3.1, 3.4.3.2	Verify that the project is not stacking credits or payments	Yes
3.4.3.3	Verify that the project is not receiving Real Estate Value benefits	Yes
3.4.1.4	Confirm that the PPEF conflict of interest and qualifications evaluation form was submitted	No
3.4.2	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the legal requirement test	No
3.4.2	Verify that the project Monitoring Plan contains a mechanism for ascertaining and demonstrating that the project passes the legal requirement test at all times	No
3.5	Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes
3.5.1	Verify the project is in compliance with laws, regulations, and contracts pertaining to not burdening mineral rights	Yes
3.6	Confirm that the project does not give rise to environmental or social harm as defined in Section 3.6. Confirm that the project has submitted the Environmental and Social Safeguards Evaluation form.	No
	If any variances were granted, verify that variance requirements were met and properly applied	No

8.5.2 Quantification

Table 8.3 lists the items that verification bodies shall include in their risk assessment and recalculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that all SSRs in the GHG Assessment Boundary are accounted for	No
5.1	Verify that the baseline emissions are calculated correctly	No
5.1.3	Verify that the appropriate OCI+ resource was used	No
5.1.3	Verify that the inputs for the oil climate index field coefficient are determined correctly.	No
5.1.1	Verify that the appropriate adjusted economic reserves approach was used.	No
5.1.1	Verify that the project meets the conditions for legal permanence, if the project is using approach 2	Yes
5.1.1, 5.1.2	Confirm the project properly applied the permanence discount and uncertainty discount as reported by the PPEF	No

Protocol Section	Quantification Item	Apply Professional Judgment?
5.3.1	Verify that the leakage discount for increased production is calculated correctly. Confirm production data by reviewing historic operational records	No
5.3.2	Confirm the project applied the appropriate market leakage adjustment for the well type	No
5.2	Verify that the project emissions were calculated according to the protocol with the appropriate data	No

8.5.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project Monitoring Plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to GHG reporting duties	Yes
6	Verify that all contractors are qualified for managing and reporting GHG emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor’s work	Yes
7.3	Verify that all required records have been retained by the project developer	No

8.5.4 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project’s verified status.

9 Glossary of Terms

Accredited verifier	A verification firm approved by the Climate Action Reserve to provide verification services for project developers.
Additionality	Project activities that are above and beyond “business as usual” operation, exceed the baseline characterization, and are not mandated by regulation.
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
CO_2 equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Direct emissions	GHG emissions from sources that are owned or controlled by the reporting entity.
Emission factor (EF)	A unique value for determining an amount of a GHG emitted for a given quantity of activity data (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Greenhouse gas (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).
GHG reservoir	A physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store or accumulate a GHG that has been removed from the atmosphere by a GHG sink or a GHG captured from a GHG source.
GHG sink	A physical unit or process that removes GHG from the atmosphere.
GHG source	A physical unit or process that releases GHG into the atmosphere.
Global Warming Potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Reductions in GHG emissions that occur at a location other than where the reduction activity is implemented, and/or at sources not owned or controlled by project participants.
Metric ton (t, tonne)	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.

MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of employees, materials, products, and waste resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g., cars, trucks, tractors, dozers, etc.).
Project baseline	A “business as usual” GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.
Project developer	An entity that undertakes a GHG project, as identified in Section 2.3 of this protocol.
Verification	The process used to ensure that a given participant’s GHG emissions or emission reductions have met the minimum quality standard and complied with the Reserve’s procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	A Reserve-approved firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol.
Cement	Any material or combination of materials fluidized and pumped into the well to provide a seal.
Certified Economic Reserves Report	Certified evaluation of the remaining economic reserve hydrocarbons attributable to a project well. This report will also contain the estimated economic lifetime remaining for the well. The Professional Petroleum Engineering Firm (PPEF) conducts this evaluation.
Decommissioning	To plug and abandon an oil and/or gas well in accordance with state and federal regulation.
Field	Group of pools, which can be vertically stacked and are within a horizontal aerial boundary.
Inactive Well	An inactive well is any oil or gas well that is no longer producing but has not yet been permanently sealed off through the process of Plug and Abandon.
Legacy Well	Wells that were drilled before well-permitting and well-plugging regulations were established.

Lifecycle Assessment	An examination of emissions generated throughout the lifecycle of a product. The life cycle assessment methodology is standardized in the International Organization for Standardization (ISO) 14040 series of standards published in 2006 and has been amended and used by stakeholders including the private sector.
Marginal Well	A producing well that is only slightly economic due to low production rates and/or high production costs from its location (e.g., far from good roads for oil pickup and no pipeline) and/or its high co-production of substances that shall be separated out and disposed of (e.g., saline water, non-burnable gasses mixed with the natural gas). Marginal wells are defined as wells that are currently producing 75 barrels of oil equivalent per day or less. Eligible marginal wells have posted production amounts greater than 0 BOE with the pertinent regulatory body in each of the 12 months prior to the project start date.
Oil and Gas Commission/ Regulator	Each state and province have a division, board, or commission responsible for overseeing the Oil and Gas (O&G) industry. These entities issue permits, collect information used to assess fees and taxes, and hire inspectors to ensure compliance with environmental and safety regulations.
Orphan Well	An unplugged well without a solvent operator.
Parts per Million	A unit of concentration frequently abbreviated to ppm. For gases, ppm refers to volume (or mole) units.
Permanence Review	Process designed to assess and ensure that the Greenhouse Gas (GHG) emissions mitigations achieved by plugging the wells are durable and sustained permanently. This concept is critical, as it ensures that the benefits of emissions reductions are not reversed.
Plug	A verifiable barrier located within the wellbore that may be mechanical or cement.
Plug and Abandon (P&A)	A.K.A Decommission - To permanently seal and retire a wellbore, usually after either it is determined there is insufficient hydrocarbon potential to complete the well, or the well has reached its economic limit. Different regulatory bodies have their own requirements for plugging operations. Most require that cement plugs be placed and evaluated across any open hydrocarbon-bearing formations, across all casing shoes, across freshwater aquifers, and perhaps several other areas near the surface, including the top 20 to 50 ft (6 to 15 m) of the wellbore.

Plugging	A.K.A Decommissioning - A well is plugged by setting mechanical or cement plugs in the wellbore at specific intervals to prevent fluid flow. The plugging process usually requires a workover rig and cement pumped into the wellbore. This methodology follows the American Petroleum Institute Wellbore Plugging and Abandonment Recommended Practice 65-3 of June 2021.
Pool	A subsurface hydrocarbon (natural gas and/or oil) accumulation.
Professional Petroleum Engineering Firm (PPEF)	This methodology requires an independent third-party hydrocarbon reserves certification, subject to the Society of Petroleum Engineers' Petroleum Reserves Management System (SPE PRMS) standards[36], from a government-licensed professional engineer with a minimum of five (5) years of hydrocarbon reserves estimation experience. The individual or entity by which they are employed will furnish the projected Economic Reserves forecast parameters and certify them accordingly. The PPEF will also conduct the Permanence Review. Details on reserves calculation can be found in Appendix C. The PPEF shall also conduct the Permanence Review. The PPEF must ensure no prior association with the Project Proponent (PP) and project (independent third party with No Conflict of Interest).
Site Remediation	Remediation of a well site, including clean-up of spills and remediation of conditions endangering public health or safety, causing contamination of water or the surface, or creating a fire hazard.
Spud	To commence drilling operations.
Temporary Abandonment Status	State of a well currently not producing oil and/or gas but that may return to production. Can also be a specific regulatory term in certain states or provinces.

[36] Petroleum Resources Management System, Revised June 2018, viewed on 16 April 2022, https://netherlandsewell.com/wp-content/uploads/2018/12/SPE_Petroleum_Resources_Management_System_2018.pdf

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Appendix A Summary of Performance Standard Development

[DRAFTING IN PROGRESS]

A.1 Assessment of Common Practice

A.2 Market Leakage

[DRAFTING IN PROGRESS] Market leakage refers to the risk that emission reductions achieved by a project are offset by an increase in emissions outside of the protocol boundary as a result of the market compensating for the oil and/or gas supply lost from a project well. When a marginal well is plugged, there is a decrease in the overall supply of oil or gas in the short term; however, the demand for it does not necessarily decrease. Thus, the reduced supply from the project well will be supplied from a different well. However, the price elasticity of demand and supply are not perfectly inelastic, so market leakage is not 100%.

When determining an accurate and conservative leakage rate, we must first assess how changes in price impact consumer demand and the GHG intensity of the new source. Additionally, since oil markets are largely driven by global economic conditions, and natural gas relies on regional markets, different market leakage rates are required depending on the type of well (i.e., production of natural gas vs oil).

Oil Market Leakage

[DRAFTING IN PROGRESS] Oil prices and production have been found to be uncorrelated.[37] Rather, crude oil prices are driven by spot prices, supply from Organization of the Petroleum Exporting Countries (OPEC) versus non-OPEC countries, supply and demand balance, financial markets, and demand in Organization for Economic Co-operation and Development (OECD) versus non-OECD countries.[38] Supply price elasticity is inelastic in the short run because capacity is fixed and increasing capacity takes time, but becomes more elastic over time as producers are able to expand production. Marginal oil and gas wells are typically already operating at a rate that is cost effective. Demand price elasticity is also elastic in both the short run and long run because oil substitutes are limited; however, they become more elastic in the long run with increased fuel efficiency and alternative forms of transportation (e.g., public infrastructure or electric vehicles).

Prest et al (2024) analyzed existing research on price elasticity of supply and demand and found an average elasticity of +0.42 and -0.33, respectively, resulting in a market leakage rate of 56%.[39] According to the U.S. EIA, roughly 17% of the US energy supply were imports, 67% of which were crude oil imports. When analyzing the second component of supply-side intervention, Prest et al found that there is a net decrease in emissions in 99.9% of scenarios due to North American reservoirs having higher emission intensity per barrel compared to the market average.

Because oil markets are a reflection of broader market conditions, the protocol applies a single, 56% market leakage adjustment for all oil well projects in the US. No additional adjustments are required to account for GHG emission intensities.

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[37] Per the Federal Reserve (2016)

[38] According to the U.S. Energy Information Agency.

[39] Brian C. Prest, Fell, H., Gordon, D. & Conway, TJ (2024). Estimating the Emissions Reductions from Supply-side Fossil Fuel Interventions. *Resources for the Future.*

Natural Gas Market Leakage

[DRAFTING IN PROGRESS] Natural gas supply-side and demand-side factors that affect price are more regional in nature. Natural gas prices respond to the amount of production, volumes in storage, and the volume of imports and exports, while demand fluctuates based on seasons, economic growth, and availability and prices of other fuels. As a result, the price elasticity of demand and supply can vary depending on region.

When determining the GHG intensity of the supplemental supply, we must consider the location of where the project well is located compared to where the supplemental supply will be sourced. The assessment includes evaluating the likelihood of imports compared to domestic production, then if domestic, where will the natural gas be produced. Additionally, we must also consider the likelihood of alternative fuels supplementing natural gas supply.

Imports

Natural gas imported from Canada contributed 99% of all annual imports in 2022.[40] The emission intensity of Canadian natural gas ranges from 1.915 gCO_2/m^3 (0.05423 gCO_2/scf) natural gas in Manitoba to 1.966 gCO_2/m^3 (0.05567 gCO_2/scf) natural gas in British Columbia, Yukon, Northwest Territories, and Nunavut provinces.[41] Comparatively, the U.S. has a natural gas emission intensity of about 0.0182 gCO_2/scf.[42] This indicates that if the natural gas supply sequestered by the project well is supplemented by natural gas imported from Canada, there will be a net increase in emissions. However, as previously stated, imports made up about 17% of US energy supply, 15% of which was natural gas – suggesting that the majority of natural gas supply as a result of supply-side intervention will likely be produced domestically. Furthermore, natural gas imports have declined since reaching its peak in 2007, while domestic production has surpassed domestic consumption.

Domestic

- Domestically, five states – Texas (24.6%), Pennsylvania (21.8%), Louisiana (9%), West Virginia (7.4%), and Oklahoma (6.7%) – accounted for over 70% of production 2022.[43]
- The Anadarko (1.83%), Arkla (3.3%), Arkoma (0.55%), East Texas (0.81%), Green River (0.06%), Gulf Coast (2.72%), Permian (9.76%), and Uinta (0.03%) basins contribute to domestic natural gas supply.[44]
- On average, transmission and distribution systems range from 25-1,693 miles from production to delivery.[45] As a result, the expected GHG emissions intensity from production through distribution varies by the upstream and downstream regions.[46]
- Conventional wells within the Uinta basin, located in the northeastern corner of Utah, that deliver to the southwest region have the highest emissions intensity (34.2 gCO2/MJ).

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40 Per US EIA.
41 According to Canada's Greenhouse Gas Offset Credit System (October 2025). Emission Factors and References Value. Values represent the "marketable" value for fuel consumed by utility, industry, residential, commercial, and transport subsectors. Available at: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/emission-factors-reference-values.html
42 Based on US EPA, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2022.*
43 Per US EIA.
44 National Energy Technology Laboratory (December 2024). *Life cycle analysis of natural gas extraction and power generation: US 2020 Emissions Profile.*
45 J. Littlefield, S. Rai and T. Skone, "Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways," Environmental Science & Technology, vol. 56, no. 22, p. 16033–16042, 2022.
46 Per National Energy Technology Laboratory (December 2024). *Life cycle analysis of natural gas extraction and power generation: US 2020 Emissions Profile.* Exhibit 6-10

Other Fuels

- Alternative fuels may include: renewable natural gas produced from organic waste (wastewater, landfill gas, livestock manure), solar, wind, and coal.
- Best case scenario is for supply to be supplemented by renewable natural gas, solar, or wind – results in a net benefit.
- Worst case scenario is for natural gas to be supplemented by coal.

Figure A.1. U.S. Regional Electricity Generation in 2024, Electric Power Sector

Electricity Fuel Source	ISO-NE	NY-ISO	PJM	SERC	FRCC	MISO	SPP	ERCOT	NWR	SW	CA
Natural gas	57%	51%	45%	42%	78%	36%	30%	46%	28%	43%	37%
Coal	<1%	<1%	16%	15%	3%	28%	24%	12%	17%	12%	3%
Nuclear	25%	20%	31%	35%	11%	15%	5%	8%	3%	21%	9%
Conventional hydropower	6%	21%	1%	5%	0%	1%	4%	0%	29%	5%	14%
Wind	3%	5%	4%	0%	0%	16%	36%	24%	15%	9%	8%
Solar	4%	2%	2%	4%	7%	3%	1%	9%	6%	8%	25%
Other energy sources	4%	1%	1%	0%	1%	1%	0%	0%	2%	2%	5%

Consumption in terms of billion kilowatt hours
Regions include New England (ISO-NE), New York (NYISO), Mid-Atlantic (PJM), Southeast (SERC), Florida (FRCC), Midcontinent ISO (MISO), Southwest Power Pool (SPP), Texas (ERCOT), Northwest and Rockies (NWR), Southwest (SW), and California (CA).
Source: Total electricity generation in the US by region and fuel source. U.S. Energy Information Agency (March 2026) *Short-Term Energy Outlook.*

Figure A.2. Consumption of Natural Gas in the U.S. by End Use in 2024

	million cubic feet	percent of total consumption
Electric Power	13,476,447	41%
Industrial Consumers	8,579,761	26%
Residential Consumers	4,389,004	13%
Commercial Consumers	3,317,883	10%
Lease and Plant Fuel	1,951,470	6%
Pipeline & Distribution Use	1,277,710	4%
Vehicle Fuel	63,626	<1%

Source: U.S. Energy Information Administration (February 2026) *Electric Power Annual*

Appendix B Development of Economic Reserves and Economic Benchmark

B.1 Professional Petroleum Engineering Firm Conflict of Interest Assessment

Project developers are required to hire a third-party PPEF to determine the well's economic reserves eligible for crediting. To ensure independence of the PPEF, all projects must demonstrate a low conflict of interest between the PPEF, project developer, and well owner and operator.

The PPEF, project developer, and well owner and operator must complete and submit the Professional Petroleum Engineering Firm Conflict of Interest and Qualifications Evaluation Form, and all parties must sign the attestation confirming compliance with the conditions outlined in this section as well as any additional criteria outlined on the evaluation form. The form must be submitted to the verification body and to the Reserve during verification.

To ensure independence of the PPEF, all projects must demonstrate a low conflict of interest (COI) between the PPEF and parties involved in the project. A COI is defined as any situation that compromises a PPEF's ability to perform a wholly independent evaluation. In order to ensure the credibility of the emissions data reported to the Reserve, it is crucial that the PPEF is completely independent from the influence of the project developer or other entities involved in the project.

Project developers are required to complete the Professional Petroleum Engineering Firm Qualifications and Conflict of Interest Assessment form.[47] All potentially conflicting services and conditions must be reported to the verification body and the Reserve during the initial verification of each crediting period. Failure to report a conflict of interest will result in the project being ineligible for crediting or require further action by the Reserve. Proceeding to evaluate economic reserves with a medium or high conflict of interest between parties may result in the project being ineligible or the economic reserves being required to be re-assessed by another PPEF.

Conflict of interest criteria include:

- Revenue Distribution Criterion: Within the three years leading up to the project start date, the combined annual revenue generated by the PPEF from the operator of the oil and gas wells and the project developer shall not exceed 5% of the PPEF's total annual revenue.
- Independence: The PPEF shall not have participated in any of the following with the operator or affiliated operator of the oil and gas wells:
    - Investment: The PPEF is prohibited from owning, acquiring, or committing to acquire, either directly or indirectly, any significant financial interest in an operator, in any corporation or entity affiliated with them, or in any property for which reserve information is to be estimated or audited.

[47] Form is available on the protocol webpage.

- Joint Business Venture Restrictions: The PPEF shall not own, have acquired, or be committed to acquiring, either directly or indirectly, any significant joint business investment with the operator or with any officer, director, principal stockholder, or other individual affiliated with the operator.
- Borrowings: The PPEF shall not be indebted to an operator, or to any officer, director, principal stockholder, or other individual affiliated with the operator. However, this does not include retainers, advances against work-in-progress, and trade accounts payable that are part of normal business transactions for purchasing goods and services, as these are not considered 'indebtedness' in the context of this regulation.
- Guarantees of Borrowings: The PPEF is prohibited from incurring debts to any individual, corporation, or other entity under conditions where repayment is guaranteed by the operator, or by any officer, director, principal stockholder, or other person affiliated with the operator. This restriction is aimed at preventing potential conflicts of interest and ensuring the PPEF's financial and operational autonomy.
- Loans to Clients: The PPEF shall not extend credit to the operator, any officer, director, principal stockholder, or other individual affiliated with them, or to any person holding a material interest in any property for which reserve information was estimated or audited. However, this does not include trade accounts receivable that are generated in the regular course of business from performing petroleum engineering and related services, as these do not fall under the definition of 'credit extension' in this context.
- Guarantees for Clients: The PPEF shall not have guaranteed any indebtedness owed by the operator or any officer, director, principal stockholder, or other person affiliated therewith or payable to any individual, corporation, entity, or other person having a material interest in the reserves information pertaining to the operator.
- Asset Transaction Restrictions: The PPEF is prohibited from purchasing any significant asset from, or selling any significant asset to, the operator, or to any officer, director, principal stockholder, or other individual affiliated with the operator.
- Restriction on Client Relationships: The PPEF is required to avoid any direct or indirect connections with the operator in roles such as a promoter, underwriter, officer, director, principal stockholder, or any equivalent capacity. Furthermore, the PPEF shall remain distinctly separate and independent from the operational and investment decision-making processes of the operator.
- Trust and Estates: The PPEF shall not act as a trustee, participant, or beneficial owner in any trust, nor as an executor, administrator, or beneficiary of any estate, if such trust or estate holds a direct or indirect interest in the operator or in any property for which reserve information has been estimated or audited.
- Contingent Fee Restrictions: The PPEF shall not be engaged by an operator to estimate or audit Reserves information under any agreement, arrangement, or understanding in which the PPEF's remuneration or fee is contingent upon, or related to, the results or conclusions of the estimation or auditing process.

B.2 Determining Economic Reserves

The Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee, comprising international oil and gas experts, collaborates with various industry-related societies to offer publicly accessible resources. These resources aim for consistent definition and estimation of hydrocarbon resources. As part of its contributions, SPE provides several key documents, including the Petroleum Resource Management System (PRMS), the PRMS Application Guidelines, a map to other systems, and standards for reserves estimating and auditing. Recognized by regulatory bodies like the US Securities and Exchange Commission (SEC), SPE stands as the foremost advisory council for petroleum engineering research. For each project, the chosen Professional Petroleum Engineering Firm (PPEF) shall be independent, unbiased, and adhere to the most recent PRMS guidelines for determining reserves.

Economic Reserves are quantities of hydrocarbons anticipated to be economically recoverable in the future (as of an effective date). The criteria for project reserves are:

1. they are discovered;
2. recoverable;
3. economic; and
4. remaining within the reservoir as of the evaluation date.

Oil and gas reserves are classified based on the certainty of recovery, and defined by the Petroleum Resources Management System (PRMS):[48]

- Proved Reserves (“P1”): quantities that can be estimated with a reasonable certainty (at least 90% probability) to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.
- Probable Reserves (“P2”): quantities that are less likely to be recovered than proved reserves, but more certain (at least 50% probability) to be recovered than possible reserves.
- Possible Reserves (“P3”): quantities that are less likely (at least 10% probability) to be recoverable than probable reserves.

P1 reserves are accessible through traditional extraction methods, such as horizontal and/or vertical drilling, while P2 reserves require enhanced recovery methods, such as water flooding or injection. Enhanced recovery methods have become less expensive in recent years, resulting in P2 reserves becoming more extractable. However, only P1 reserves (i.e., economic reserves) are eligible for crediting under the protocol.

The well’s economic reserves must be evaluated by a qualified independent, third-party[49] Professional Petroleum Engineering Firm (PPEF). If multiple wells are reporting under a single project, the same PPEF must conduct all evaluations. The economic reserves must be evaluated in accordance with the most recent version of the PRMS and Guidelines for the Application of the Petroleum Resources Management System. PPEF may use their professional judgement to determine which analysis procedure to use based on the well and reservoir characteristics. The PPEF should use more than one analysis method to determine the economic reserves. In instances where the quantity of economic reserves differs between analyses, then the most conservative value must be used for purposes under the protocol. The evaluation report must include a narrative of the analyses used and the estimated economic reserves from each analysis. The report must clearly state the quantity of economic reserves recoverable in the first 10 years of the project and the quantity recoverable in the subsequent 10 years.

PPEF report must be completed no earlier than 12 months prior to the date the well completes P&A activities, or the economic reserves must be re-evaluated.

[48] Available at: https://www.spe.org/en/industry/reserves/

[49] PPEF must meet the requirements outlined in Section 3.4.1.1.1

If the well continues to extract hydrocarbons while the economic reserves are being assessed and before the well is P&A, then the quantities of extracted reserves must be deducted from the reserves identified in the PPEF report. The PPEF report must have an addendum (or similar) modification to the report to revise the economic reserves.

A further refinement (specific to a project's additionality criteria) is that only volumes designated as proved developed producing reserves qualify as candidate volumes that currently satisfy additionality criteria according to this methodology. Proved developed producing (PDP) reserves, volumes expected to be recovered from wellbore intervals that are producing at the time of abatement project commencement.

They are also determined to be economically recoverable under existing technical and commercial conditions with reasonable certainty using geoscience and engineering analysis. Proved Developed Non-Producing (PDNP) reserves, include potential volumes in shut-in wells or behind wellbore casing pipe of currently producing wells. These volumes can be economically returned to production with minor capital costs with reasonable certainty. Currently, these volumes are not included in this methodology.

The approaches for modeling economic reserves include material balance, history matched simulation, decline curve analysis, and/or rate-transient analysis. The confidence in results increases when the estimates are supported by more than one analytical procedure. The three most widely used are:

1. **Material balance:**

Material balance methods used to estimate recoverable quantities involve the analysis of pressure depletion as reservoir fluid is withdrawn. Project evaluation shall accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

2. **Production Performance Analysis Methods:**

Oil and gas production rates decline over time. Analysis of this change in combination with produced fluid ratios versus time and cumulative production as reservoir fluids are withdrawn, provides useful information to predict ultimate recoverable volumes. Decline Curve Analysis (DCA) is a graphical procedure used for analyzing production decline rates and forecasting future performance of oil and gas wells, including remaining technically recoverable volumes. Reliable results require a sufficient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators shall consider additional factors affecting production performance behavior, such as variable reservoir and fluid properties, transient versus stabilized flow regimes, changes in operating conditions, interference effects from offset wells, and depletion mechanisms.

3. **Analogy to other similar projects:**

The analogy method for estimating reserves involves directly comparing a newly discovered or poorly defined reservoir with a known reservoir that is believed to have similar geological or petrophysical properties, such as depth, lithology, porosity, and so on. While this method is considered the least accurate among the techniques presented, it is commonly used in the initial stages of a reservoir's life to provide an initial, rough estimate of recovery potential. As more data becomes available, allowing for more precise volumetric Original Oil in Place (OOIP) or Original Gas in Place (OGIP) estimates, the analogy method is often employed to define a range of potential recovery factors for these in-place volumes. This approach is especially valuable when some performance history is available, but a decline rate has not yet been established. It is crucial, however, to use analogy in conjunction with other, more computationally intensive methods to ensure that the results are consistent with the geological framework of the reservoir.

The PPEF should follow the PRMS and Application Guidelines to the PRMS to estimate the economic reserves. In cases where the PPEF uses multiple evaluation analysis methods, the most conservative estimate of the economic reserves must be used for quantification. Some overestimations have occurred for undeveloped reserves or new production. In cases in which reserves estimates provided by a PPEF have historically needed to be revised for mature PDP reserves, in the aggregate, these revisions have been increases to previous estimates.

B.3 Development of the Economic Limit

Many wells are not plugged and eventually become orphan wells when the operator of record becomes insolvent or otherwise ceases operations. Based on Enverus data, wells that are plugged typically do so when they reach the regulatory burden in their respective jurisdictions. In the United States, regulators generally permit a well to continue production until it has depleted its economic reserves. Following this, most regulators allow wells to remain idle for an extended period before mandating Plug and Abandonment (P&A).

Although less common, there are instances where operators choose to plug wells when they cease to be economically viable, which is the earliest point at which operators generally consider plugging wells, as observed by Enverus data. To conservatively estimate the baseline emissions, the protocol assumes that the well will continue to produce and extract all economic reserves. The “economic limit” is the point at which the production rate equals the maximum cumulative net cash flow, meaning, continued production is no longer economically viable. This assumption establishes a baseline emissions scenario that represents a business-as-usual case, thereby minimizing the risk of over-crediting.

Projects are required to demonstrate that the project well remains economically viable, and the early plugging of the well is not financially advantageous as of the project start date (i.e., date well is plugged). The project developer must determine the economic limit (i.e., production rate when the project reaches the maximum cumulative net operating cash flow) of each well according to the PRMS and Application Guidelines to the PRMS.

To determine the economic limit, the following information is required:

1. Estimated P1 reserves as of the start date (economic reserves)
2. Estimated revenue from the reserves
3. Historic operating costs

The estimated revenue from the economic reserves (as defined by the PPEF) represents the business as usual scenario if the well continued to extract and sell hydrocarbons until all economic reserves are depleted. To estimate the potential revenue, the protocol must define the future price of oil and natural gas. Prices for oil is responsive to world markets and events, while natural gas prices are responsive to regional conditions. For instance, oil prices may increase as a result of conflict, such as policy disputes or wars. Natural gas prices typically fluctuate based on seasonal demand, domestic production, rate of imports, and rate of exports.

Oil prices fluctuate frequently based on global market conditions, highlighting the need for a dynamic price estimate model for marginal wells with an economic life often exceeding a decade or more. This protocol utilizes the U.S. Energy Information Agency (EIA) Annual Energy

Outlook[50] (AEO) report to estimate the cost per barrel of the hydrocarbon for the project's economic life. The annual report evaluates long-term energy trends in the United States, including consumption and supply trends. While the US EIA does release monthly Short-Term Energy Outlook reports, the AEO is better suited for long term forecasting for the purposes of this protocol.

The AEO models a reference case, as well as high and low scenarios for oil and gas prices, supply, economic growth, and alternative fuels. The reference case assesses energy markets under current regulatory conditions and technical growth assumptions. Table B.1 below summarizes the AEO2025 forecasts for the low, reference, and high cases for 2050 values.[51]

Table B.1. Annual Energy Outlook 2025 Modeled Cases

Modeled Case	Low	Reference	High
Oil and Gas Prices[a]	$47/barrel	$91/barrel	$155/barrel
Oil and Gas Supply[b]	-50%	N/A	+50%
Economic Growth[c]	1.2%	1.8%	2.1%

[a] Prices are based on forecasted Brent spot prices.
[b] Supply values are in reference to percent change from the reference case, reflecting rate of onshore recovery, undiscovered resources in Alaska and offshore, and technological improvements.
[c] Economic growth cases refer to the compound annual growth rate for US GDP

The most recent AEO report available at the time of the evaluation must be used to determine the future price of the economic reserves. When forecasting revenue from the economic reserves, the evaluation must be conducted on a year-by-year basis, such that the expected production in a given year is multiplied by the AEO forecasted price for that year. If the economic life exceeds the AEO forecasted prices, then the latest price available should remain constant up until the project reaches its economic limit date. Project developers must use the reference case price model for the Henry Hub natural gas spot price (specified year dollars per MMBtu) or the West Texas Intermediate spot crude oil prices (specified year dollars per barrel).

To determine operating costs, the project must the previous 12 months (from the project start date or when the well ceased production prior to plugging the well) of lease operating cost statements from the operator, at a minimum. The PPEF must confirm that the project well is typical for the field and that the average costs from the lease operating statement are representative. Well-level cost details are acceptable for atypical wells in a field.

[50] EIA Annual Energy Outlook is released every spring and forecast prices through 2050. Most recent report is available here: https://www.eia.gov/outlooks/aeo/
[51] For more information on the key assumptions for each models, please refer to the EIA website.Available at: https://www.eia.gov/outlooks/aeo/assumptions/

Appendix C The Oil-Climate Index

Baseline emissions are determined by the life cycle emissions of the oil and gas supply chain from production to end-use. The life cycle assessment (LCA) methodology is standardized in the International Organization for Standardization (ISO) 14040 series of standards published in 2006 and has been amended and used by stakeholders in the private sector.

The protocol requires the use of the Oil Climate Index (OCI$^+$) analytic tool, developed by the Carnegie Endowment's Energy and Climate Program (CEECP) and Rocky Mountain Institute (RMI), to quantify the baseline emissions. The OCI$^+$ Tool is a bottom-up systems tool that also uses input top-down measurements (hybrid approach) to quantify emissions from oil and gas production, processing, refining, shipping, and end uses.[52]

- **Upstream GHG emissions** are generated by extraction activities of oil and gas during the well's operational life. These include process emissions during extraction operations, such as venting, flaring, and fugitive emissions. Emissions data is estimated from product specific LCA models or more accurate/conservative well-specific data, if available. Because all the wells included in the project activities will be existing wells, emissions from exploration and drilling are excluded from the baseline. The upstream model, Oil Production Greenhouse Gas Emissions Estimator (OPGEE) was developed and expanded by researchers at Stanford University.[53]
- **Midstream GHG emissions** are generated by processing and refining the oil and gas products during the well's operational life. These include process emissions as well as any emissions from energy use and fuel consumption during refining operations. Emissions data is estimated from product specific LCA models or more accurate/conservative well-specific data, if available. The midstream model, Petroleum Refinery Life Cycle Inventory Model (PRELIM) was developed and is being updated by researchers at the University of Calgary[54].
- **Downstream GHG emissions** from avoided fuel use attributable to the quantity of oil and gas production abated will be estimated through auditable third-party oil and gas reserves analysis. Data inputs require a detailed product slate (in barrels or kilograms of product per barrel of oil) to calculate both the greenhouse gas (GHG) emissions associated with transporting petroleum products from the refinery outlet to the end use destination and the GHG emissions associated with petroleum product combustion. The downstream model, OPEM (Oil and Gas Products Emissions Module) was developed by researchers at the Carnegie Endowment for International Peace, Koomey Analytics, and the Watson Institute at Brown University.[55]

[52] Climate Trace (2023), "Independent Greenhouse Gas Emissions Tracking". https://climatetrace.org/
[53] Stanford University (2023). "Oil Production Greenhouse Gas Emissions Estimator," https://github.com/arbrandt/OPGEE
[54] University of Calgary (2022), "PRELIM: The Petroleum Refinery Life Cycle Inventory Model", https://www.ucalgary.ca/energy-technology-assessment/open-source-models/prelim
[55] Rocky Mountain Institute (2023) Oil Products Emissions Model https://github.com/RMI/OPEM

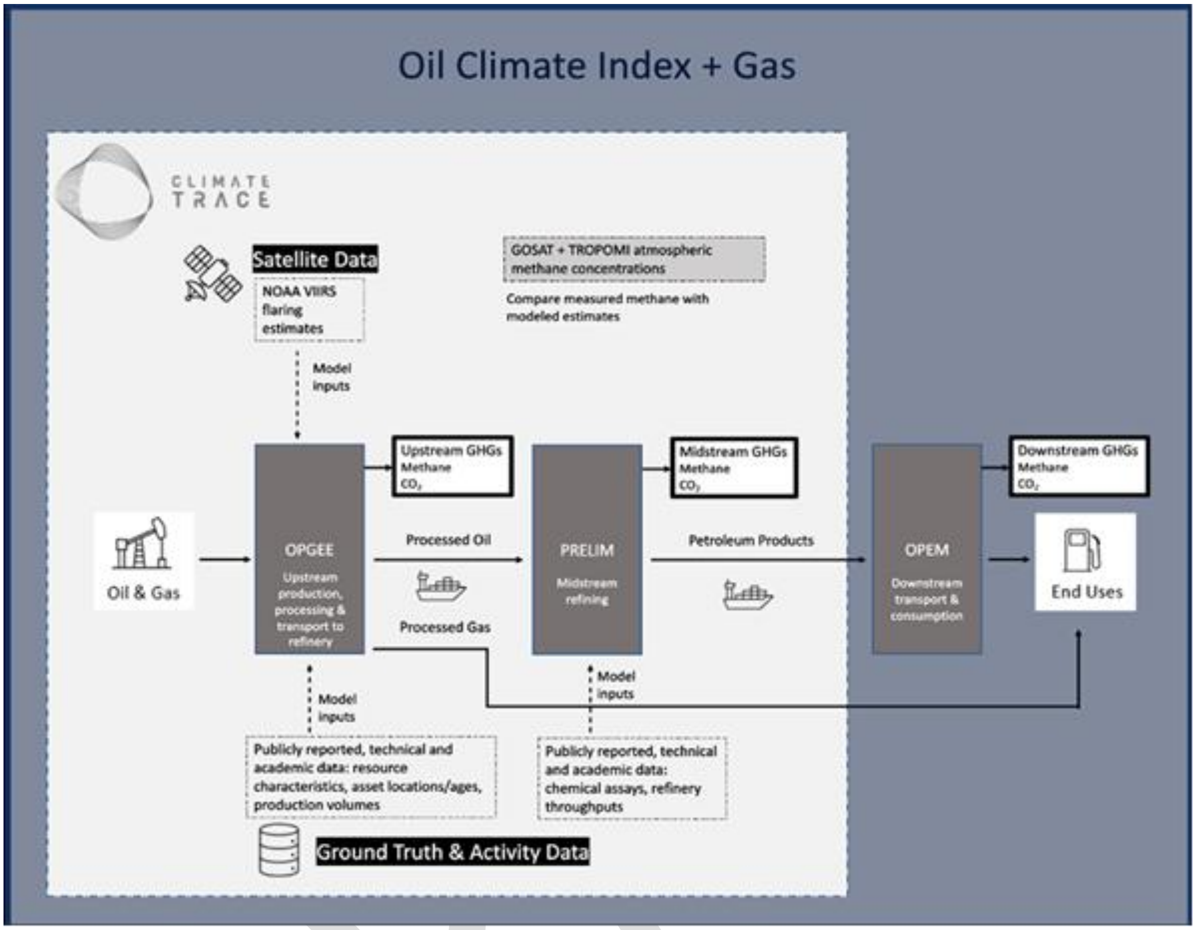


Figure C.1. The Oil Climate Index + Gas Diagram

OPGEE models emissions associated with the extraction and processing of oil, gas, and other compounds stemming from the reservoir. Gas flows through OPGEE all the way to distribution, with user-defined options to also analyze gas at the field or transmission line. OPGEE models the oil transported from surface processing to the refinery gate. From here, refinery oil flows are modeled after PRELIM. Finally, OPEM uses the product slates modeled in PRELIM and the gas flows modeled in OPGEE to estimate product transport and end-use consumption emissions. OPEM also includes the transport and combustion of petroleum coke (petcoke) that is removed upstream when upgrading extra-heavy oils and natural gas liquids that are separated from light oils and wet gasses at the field. Thus, the OCI⁺ estimates the sum of the results from these three models, which equals the total life-cycle emission intensity of a barrel oil equivalent through the entire supply chain.[56]

C.1 Oil Production Greenhouse Gas Emissions Estimator

Stanford University developed this model, with significant assistance provided by the California Air Resources Board. OPGEE is an engineering-based LCA tool for the measurement of GHG emissions from the production, processing, and transport of crude petroleum.

[56] Environmental Protection Agency (2018), “Emission Factors for Greenhouse Gas Inventories”. https://www.epa.gov/sites/default/files/2018-03/documents/emission-factors_mar_2018_0.pdf

By using 'Smart' defaults, OPGEE can produce reasonable estimates based on a reduced number of key data inputs.

- Extraction method specifications (primary, secondary, enhanced oil recovery, or other)
- Level of activity per unit of production
  - Water-to-oil ratio (for primary and secondary production)
  - Steam-to-oil ratio (for tertiary production)
  - Flaring rate
  - Venting rate (level of fugitive emissions)
- Location (onshore or offshore, with GIS coordinates)

C.2 Petroleum Refinery Life Cycle Inventory Model

PRELIM is a crude refining process model that provides an estimate of the emissions and product slate volumes generated by a refinery for each barrel of crude processed. It has been developed by researchers at the University of Calgary. For the purposes of the OCI$^+$, PRELIM is used to estimate the oil refining emissions associated with crude output from a given upstream field.

These model results do not trace individual barrel supply chains from the field to a specific refinery. Rather, provide an estimate of the likely refinery complexity and associated emissions based on the crude properties.

C.3 Oil Products Emissions Module

OPEM estimates two emissions sources:

1. the transport of petroleum products by shipping entities and the end use of all petroleum products by various consumers.
2. The combustion of natural gas and petroleum products by consumers (Scope 3 emissions) is increasingly being considered in this sector's climate impacts.

OPEM considers all associated oil and gas products that are consumed. Historically, petroleum end use centered only on transport fuels, including gasoline and diesel, and ignored or incompletely and inconsistently reported GHG emissions from petroleum co-products like petcoke, fuel oil, residual fuels, asphalt, and petrochemical feedstocks. OPEM v.3.0 includes these co-products, as well as gas and natural gas liquids that were produced along with each barrel of crude.

OPEM estimates emissions using combustion, transport, and process emissions factors reported by the United States Environmental Protection Agency for GHG inventories and Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model. Emissions factors are documented here. Note that the EPA assumes high fuel quality and near-complete fuel combustion in the calculation of published combustion emissions factors. Depending on the quality of the engine in which a fuel is burned, EPA emissions factors may result in a best-case (lowest emissions) estimate. The model also assumes some percentage of ethane is converted to ethylene for petrochemical use, and assumes a conversion process emissions intensity, but does not include emissions associated with further processing and use of the ethylene product, nor does it include other petrochemical processes.[57]

[57] Rocky Mountain Institute (2023) Oil Products Emissions Model https://github.com/RMI/OPEM

Given current limitations posed by the reporting of global petroleum product transport data, the OCI+ assumes that lighter petroleum liquid products (petrochemical feedstocks, gasoline, diesel, jet fuel, NGL, LPG) are transported via pipeline 2,414 kilometers or 1,500 miles (the equivalent distance from Houston to New York) and then by heavy duty tanker truck 380 kilometers or 236 miles (the equivalent distance to either the Washington, DC or Boston metropolitan areas). Heavy liquid products (fuel Oil, residual fuels) are assumed to travel 1,200 km by rail, 1,200 km by tanker, and 500 miles by truck. Solid fuels (petroleum coke and sulfur) are assumed to travel 3,352 km by tanker and 750 miles by rail. Users can input different distances, shipping modes, and shipping fuels into OPEM to model different transport scenarios.

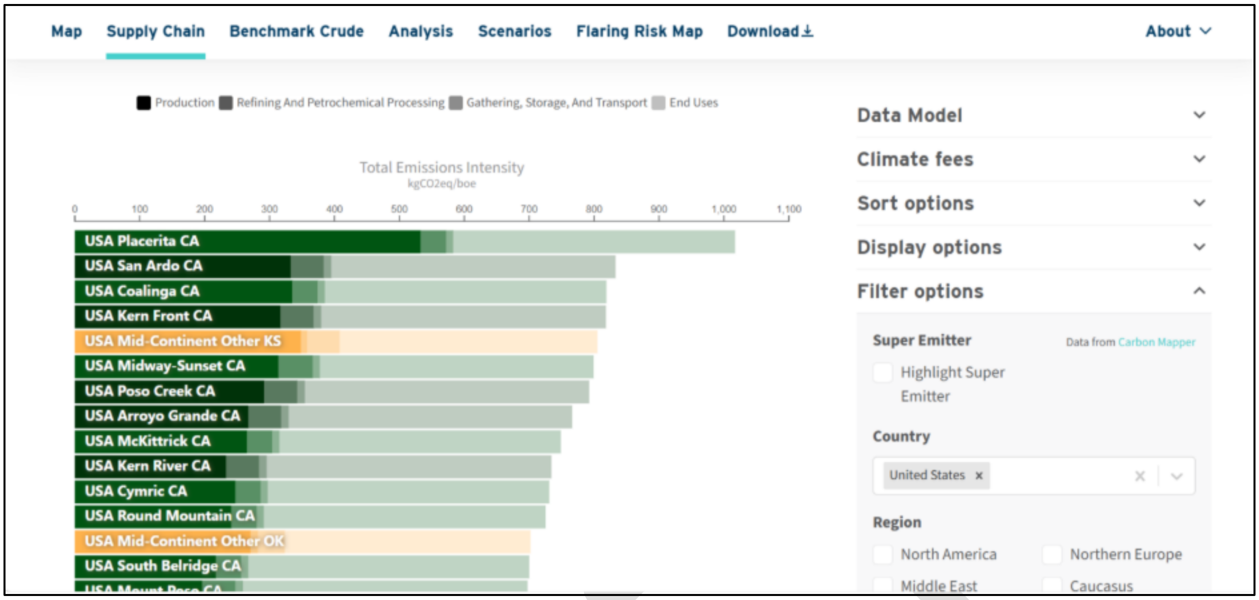
Natural gas processing and transport emissions are computed through the OPGEE model and therefore are not part of OPEM. Details for the calculation of emissions from natural gas pipelining and LNG shipping can be found in the OPGEE documentation.

C.4 Oil Climate Index Field Coefficient

The baseline emissions are quantified based on the adjusted economic reserves and the Oil Climate Index Field Coefficient. To determine the Oil Climate Index Field Coefficient (in Equation 5.5), project developers must use the OCI+ tool to identify the emissions from production, refining and petrochemical processing, gathering, storage and transportation, and end uses. Production emissions should exclude the emissions associated with drilling and exploration. All data is reported in terms of the annual total emissions intensity per barrel of oil equivalent (kg CO_2e/BOE) for the resource. The resource must be selected based on where the project well is located.

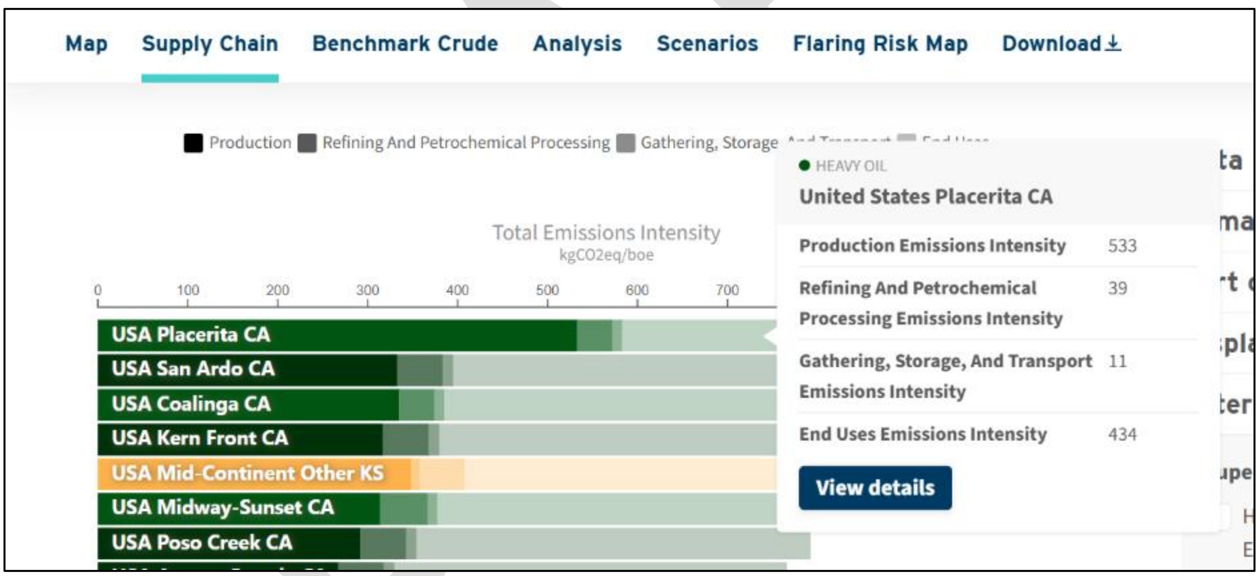
Below are directions on how to use the OCI+ tool under the protocol. Please note that the step is under the applicable graphic.

Step 1: Go to the “Supply Chain” tab on the OCI+ tool website.

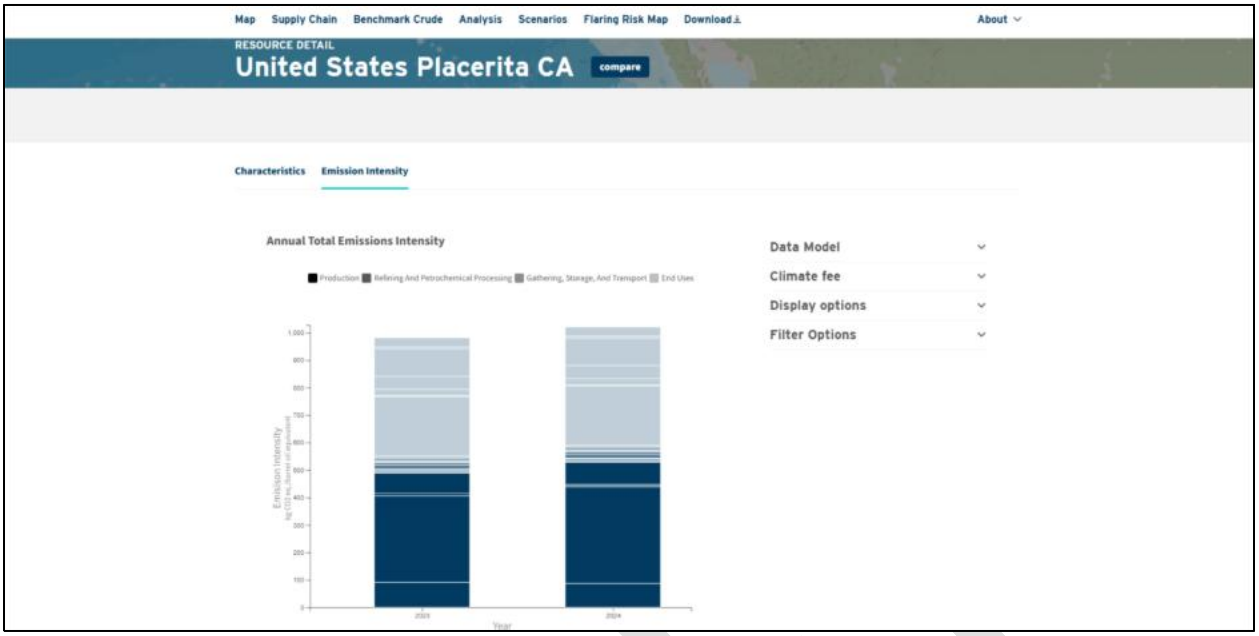


Step 2: In the “Controls” panel, select “United States” under the filter options.

Step 3: Identify the resource for which the project well is located.

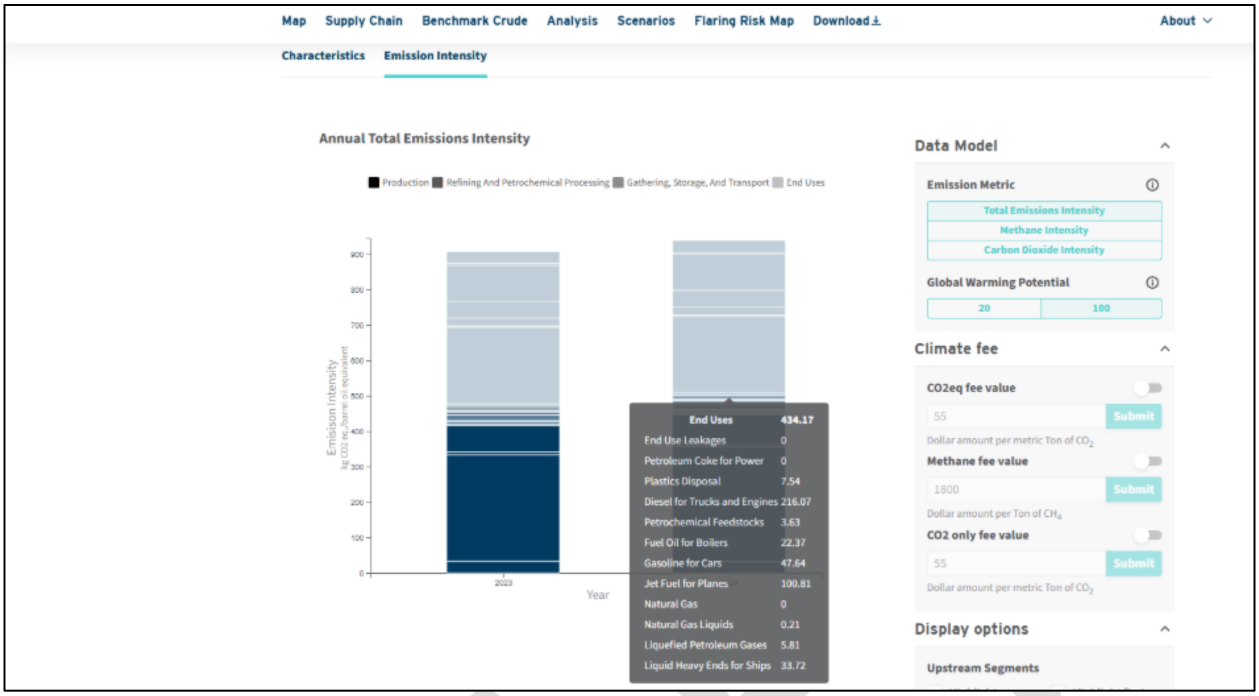


Step 4: Hover over the resource and select “Details”.



Step 5: Go to the "Emissions Intensity" tab.

Step 6: In the "Controls" panel, change the emissions metric to "Total Emissions Intensity" and Global Warming Potential to "100".



Step 7: Record the total emissions intensity for production, refining and petrochemical processing, gathering, storage, and transportation, and end uses. The emissions intensity value must be the same year as the reporting period. If the reporting period spans two calendar years, the emissions must be aggregated accordingly.

Appendix D Permanence Deduction for Reservoir Communication

Oil and gas reservoirs are permeable rather than discrete, defined boundaries. As a result, when a well is plugged and abandoned, a portion of the sequestered reserves may be accessible by other wells under certain conditions. This would give rise to secondary effects, or leakage. Project developers may voluntarily plug a well to increase pressure within the reservoir to increase production rates of a nearby well. The secondary effects may occur intentionally or unintentionally. To address such concerns, the Protocol requires that project developers conduct a reservoir communication risk assessment.

The protocol employs a procedure developed by Netherland, Sewell & Associates, where a Professional Petroleum Engineering Firm (PPEF) is required to make a technical determination with reasonable certainty that the volume of oil and gas could be successfully sequestered by remediating a well or a group of wells:

1. **Determining the Area of Review (AoR):** The PPEF must analyze the geological conditions of the reservoir to establish an AoR for the reservoir communication risk assessment. All wells within the designated AoR must be assessed according to procedure 1a and 1b. The AoR guidelines are provided in Appendix D.1.
2. **Procedure 1a and 1b:** The PPEF must demonstrate the level of risk that the sequestered reserves will be recovered by each well within the AoR. Procedure 1a and 1b are outlined in Appendix D.2.
3. **Qualitative Technical Review:** If a project cannot demonstrate to a reasonable level of certainty that the reserves will not be recovered by each well within the AoR, then a qualitative technical review must be conducted to determine the permanence deduction and uncertainty deduction. The qualitative technical review guidelines is provided in Appendix D.3.
4. **Annual Permanence Monitoring:** All projects must monitor the risk of impermanence and demonstrate compliance every verification period. Annual monitoring procedures are outlined in Appendix D.4 and Section 6.

D.1 Determining the Area of Review

This procedure is designed to be universally applicable across various environments and situations. However, the most effective determinations are made through the application of engineering and geoscience analysis, combined with informed professional judgment, tailored to the specific circumstances at hand.

The primary guiding principle for delineating the AoR is that, unless there is a significant deviation from current development techniques and production practices, new development or production outside of the AoR should not, with reasonable certainty, impact the sequestered volumes.

The following steps outline the process:

1. **Identification of Structural Features:** Map any nearby structural features like faults, saddles, spill points, etc., that are known to function as barriers to pressure and/or hydrocarbon fluid flow.
2. **Stratigraphic Features:** Identify and map stratigraphic features such as pinch-outs that limit the extent of the reservoir or the zone of interest.

3. **Petrophysical Features:** Map fluid contacts or other petrophysical features that define the current extent of producible hydrocarbons.
4. **Pressure Communication Limits:** If previously demonstrated through interference testing, define a boundary around Well A's completion. This boundary should have a fixed radius, equal to the shortest distance between any producing part of Well A's completion and the nearest non-interfering offset well producing from the same reservoir/zone. Note: For a vertical Well A, this boundary will be circular. For a horizontal Well A, the boundary may be more complex in shape.
5. **Defining the AoR:** If the data from Steps 1 to 4 adequately define a fully bounded area around Well A, the AoR is the smallest area containing Well A, formed by any combination of segments of these defined boundaries.

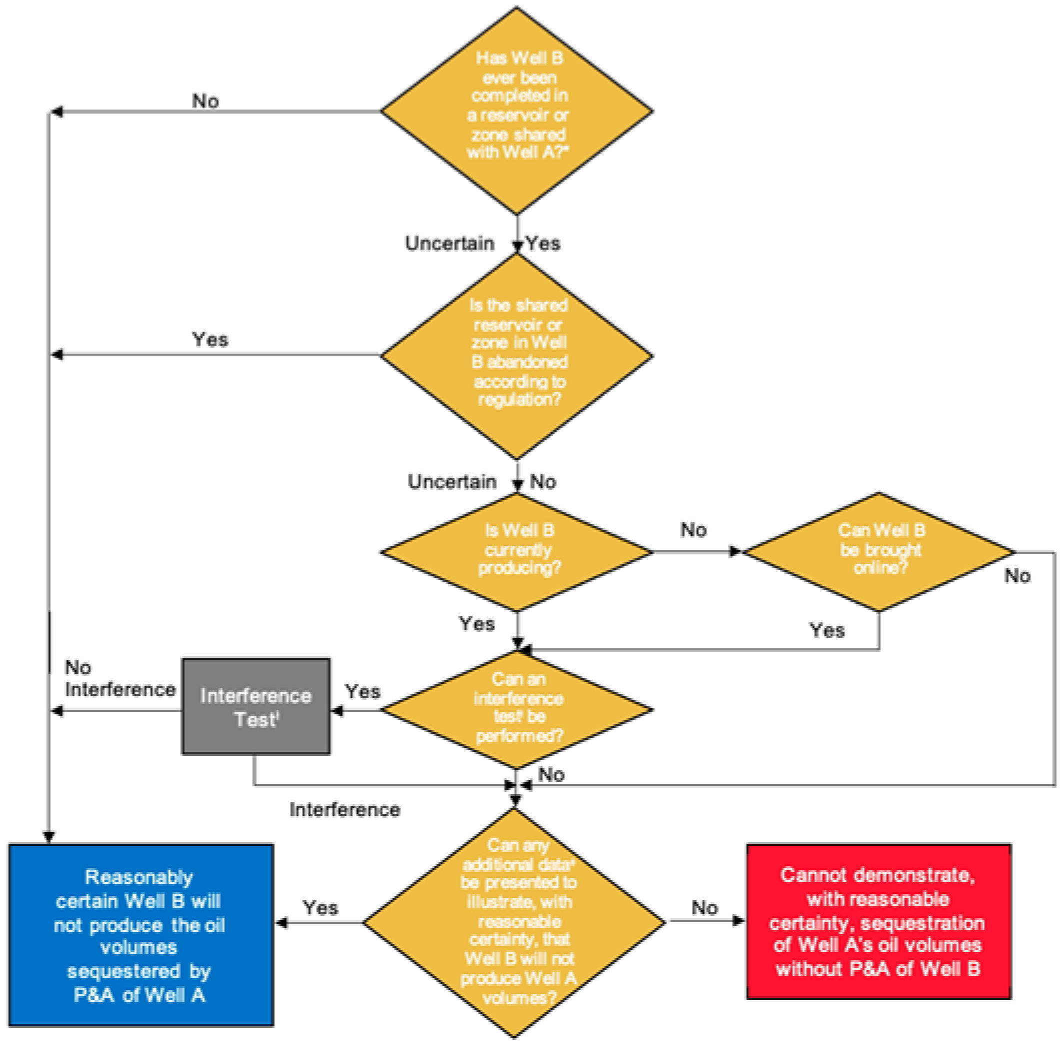
As an alternative approach, it may be acceptable to use an analogy to similar wells in the same field and producing from the same reservoir/zone, particularly where interference testing has been conducted previously. If there is ample analog data, the probability distribution of distances to the nearest non-interfering offset wells should be considered to ensure reasonable certainty.

Reasonable certainty shall be defined as the condition where the probability distribution of distances to the nearest non-interfering offset wells is evaluated with a high degree of confidence, based on the professional judgment of the PPEF. The PPEF's expertise, combined with available analog data, ensures that the analogy to similar wells reflects accurate and conservative estimates. While this assessment is qualitative in nature, it is grounded in industry best practices and the professional experience of the PPEF to ensure the reliability and conservativeness of the conclusions drawn. In the absence of empirical analog data, defining the AoR using local regulatory spacing requirements or the historical prevailing field development spacing for the reservoir/zone may be acceptable.

D.2 Procedure for Demonstrating Permanence of a Single Well

All projects must demonstrate the impermanence risk associated with reservoir communication through the use of Procedure 1a and 1b below. The project well, referred to as "Well A", must be assessed against each well within the AoR, referred to as "Well B."

If the PPEF is unable to demonstrate with reasonable certainty that the risk of the sequestered reserves will be recoverable by Well B, then more information must be provided and the PPEF will continue the analysis according to Procedure 1b. However, if more information is not able to be provided, then they are unable to demonstrate with a reasonable certainty that the risks are negligible.



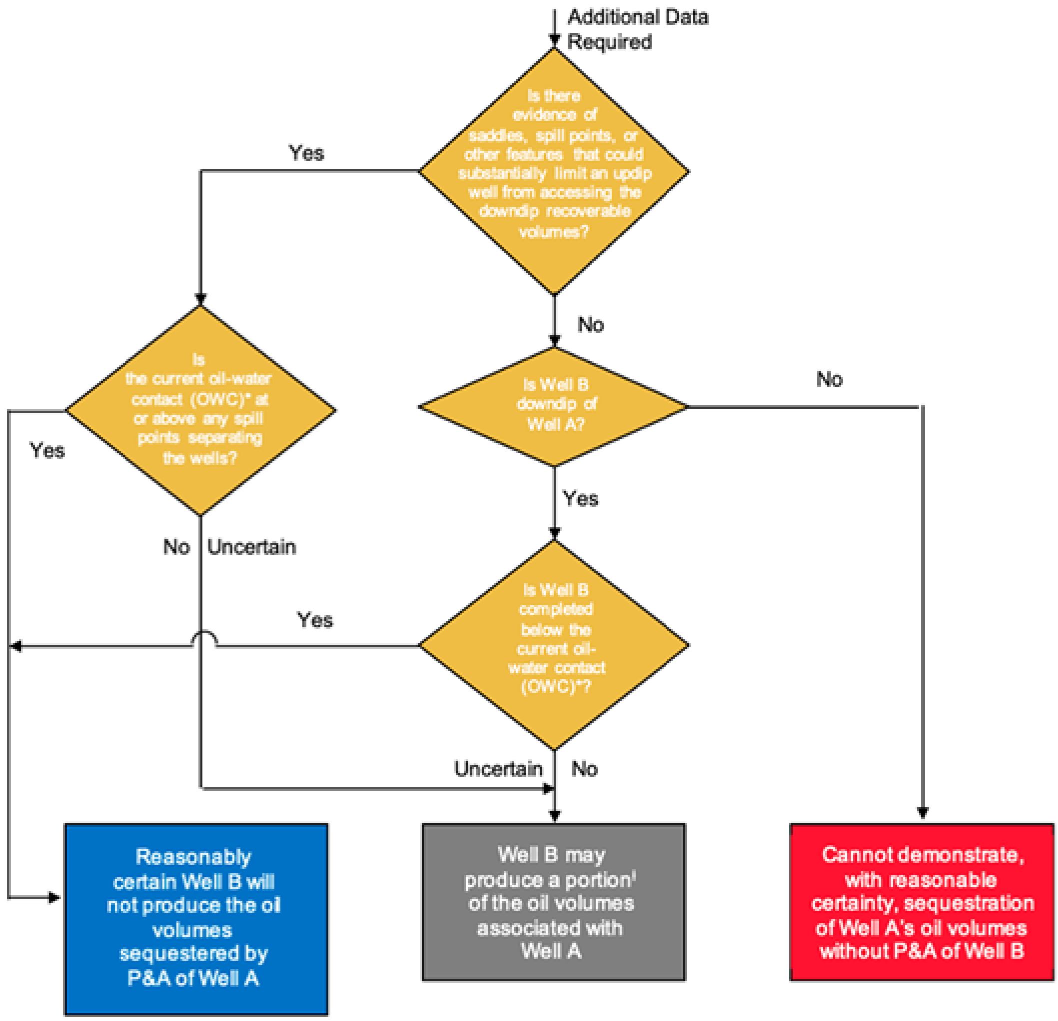
*Excluding zones demonstrated, with reasonable certainty, to have minimal pressure communication to Well A, such as by sealing faults, shale layers, baffling, etc.

'An interference test would typically consist of shutting in Well A and flowing Well B at a constant rate for a baseline period, running a high-frequency downhole pressure gauge to the perforations in Well A, and monitoring for a pressure signature upon shutting in Well B that would indicate pressure communication between the wells.

'Various petroleum engineering and geoscience analyses may be capable of satisfying this test, depending on available data and technical details, such as reservoir type, drive mechanism, historical production data, etc. For one illustrative example, please see Procedure 1a for a conventional oil reservoir with water drive.

Figure D.1. Procedure 1a to demonstrate the permanence of a well

Procedure 1b below should be used for a conventional oil reservoir with water drive to demonstrate with a reasonable certainty that oil volumes sequestered by P&A of Well A will not be produced by existing well B, given that Procedure 1a resulted in the need for more information.



**The oil-water contact (OWC) can be defined using data or a combination of data including (but not limited to) core data, open- and cased-hole logs, historical production data, repeat formation tester pressure data, and seismic surveys.*

[1]The portion of oil volumes potentially associated with Well A that may be produced by Well B could be quantified using the height of the oil column between the OWC and the shallowest point where volumes are accessible to Well B.

Figure D.2. Procedure 1b to demonstrate the permanence of a Project's well.

If the PPEF can demonstrate with reasonable certainty of negligible reservoir communication of sequestered reserves according to Procedure 1a and 1b, a permanence deduction is not required in Equation 5.4.

If the project cannot demonstrate reasonable certainty (red box) or the analysis determines there is a risk of reservoir communication (gray box), a qualitative permanence review must be conducted (see Section D.3).

D.3 Qualitative Permanence Review

Reservoir communication can be nascent or otherwise not affect a project's permanence during and after the crediting term. However, Procedures 1a & 1b are designed to delineate between projects that will require a permanence deduction and those that will not. If the application of engineering and geoscience analysis to the available data cannot achieve reasonable certainty of sequestration under Procedures 1a & 1b, engineering and geoscience judgment may be applied to qualitatively classify a potential project along two key dimensions:

1. the percentage of project volumes that are economically recoverable from existing offset wells
2. the conclusiveness of the available data and associated analysis

The qualitative best estimates for each of these dimensions will be characterized as Low, Medium, or High. The resulting matrix of potential classifications will be used to determine the extent to which a project shall apply a permanence deduction and/or uncertainty deduction. The deduction values provided below are designed to be conservative, particularly in the case where a higher portion of volumes may be recoverable, or the data conclusiveness is low. The matrix framework provided below was developed by Netherland, Sewell, and Associates to reflect conservative, categorical risk framework intended to avoid over-crediting in situations of elevated reservoir communication risk or limited data conclusiveness.

The project developer shall submit a descriptive report prepared by the PPEF that includes a compilation of project data. Leveraging the matrix described below, the PPEF will place each well in a certain risk bucket based on conclusiveness of available data and the percentage of volumes of reserves recoverable by offset wells. This report and the expert opinion of the PPEF will provide the project developer with the permanence adjustment and any applicable uncertainty adjustment.

% of Reserves Recoverable from Offset Wells	Conclusiveness of Available Data: LOW	MEDIUM	HIGH
HIGH	**HL** Project not eligible for crediting	**HM** Project not eligible for crediting	**HH** Project not eligible for crediting
MEDIUM	**ML** 20% Permanence Discount across total economic reserves. Uncertainty discount of 5%	**MM** 20% Permanence Discount across total economic reserves. Uncertainty discount of 1%	**MH** 20% Permanence Discount across total economic reserves. No Uncertainty discount
LOW	**LL** 5% Permanence Discount across total economic reserves. Uncertainty discount of 5%	**LM** 5% Permanence Discount across total economic reserves. Uncertainty discount of 1%	**LH** 5% Permanence Discount across total economic reserves. No Uncertainty discount

Figure D.3. Qualitative Permanence Review Matrix

D.3.1 Percentage of Volumes of Reserves Recoverable

In determining the amount of reserves to be credited by the early plugging of any given project well, the truncated reserves analyzed in a qualitative permanence review must be discounted for impermanence risk. While it is not possible to detail every combination of geological characteristics, the qualities listed below may be taken as generally representative.

The following guidelines shall be used to classify low, medium, or high percentage of volumes of reserves recoverable by a non-project well.

Low: 5% Permanence Discount

- Well B shows limited historical signs of interference or communication with the project well
- Producing reservoir is largely depleted of energy, such that well B drawdown is unlikely to mobilize hydrocarbons from the project well drainage area
- Mobility ratio of water to the hydrocarbon phase is high and producing watercut at the Well B is high, such that additional hydrocarbon sweep is likely to be limited
- Well B is far from the project well relative to typical analog development spacing
- Well B is lower on structure than the project well in a conventional reservoir
- Well B was completed with a low volume of proppant and fluid relative to typical analog completions in an unconventional reservoir
- Well B is separated from the project well by an injection well such that the injected phase is likely to limit the hydrocarbon phase relative permeability in the rock

Medium: 20% Permanence Discount

- Well B shows moderate historical signs of interference or communication with the project well
- Producing reservoir still has active drive mechanism, such that offset well drawdown is likely to mobilize hydrocarbons from the project well drainage area
- Mobility ratio of water to the hydrocarbon phase is moderate and producing watercuts at both the project well and offset well are moderate, such that additional hydrocarbon sweep is likely
- Well B is somewhat close to the project well relative to analog development spacing
- Offset well is at a similar position on structure as the project well in a conventional reservoir
- Well B was completed with a high volume of proppant and fluid relative to typical analog completions in an unconventional reservoir

High: Project Well Not Eligible

- Well B shows strong historical signs of interference or communication with the project well
- Producing reservoir has highly active drive mechanism with high sweep efficiency, such that most of the hydrocarbons from the project well drainage area may be swept to Well B
- Mobility ratio of water to the hydrocarbon phase is low and producing watercuts at both the project well and offset well are low, such that substantial hydrocarbon sweep is likely
- Well B is very close to the project well relative to analog development spacing
- Well B is higher on structure than the project well in a conventional reservoir

- Project well is located between the Well B and an injection well such that the hydrocarbon phase is likely to be displaced toward the offset well

D.3.2 Quality and Conclusiveness of Data

While it is not possible to detail every combination of data conclusiveness to determine the uncertainty discount, the qualities listed below may be taken as guidance:

Low: 5% Data Conclusiveness Discount

- Early in property life
- Little data beyond public production records
- Little or no geologic context available
- Long remaining economic lives for offset producers
- Conflicting or unreliable data

Medium: 1% Data Conclusiveness Discount

- Established production trends
- Some operator data available on wellbores and well histories
- Basic understanding of geologic structure
- Moderate remaining economic lives for offset producers
- Interpretation supported by only one or two data points

High: No Data Conclusiveness Discount

- Mature properties at or near terminal decline
- Substantial operational data available over long time horizons
- Detailed understanding of geology, including sealing faults
- Short remaining economic lives for offset producers or operator guarantee of end of field life
- Multiple independent approaches to analysis point to the same conclusion

D.4 Annual Permanence Monitoring

All projects must demonstrate, with a reasonable level of certainty, that the oil volumes sequestered by P&A of the project well will not be produced by wells drilled after the project start date. The assessment must be conducted as outlined in Figure D.4.

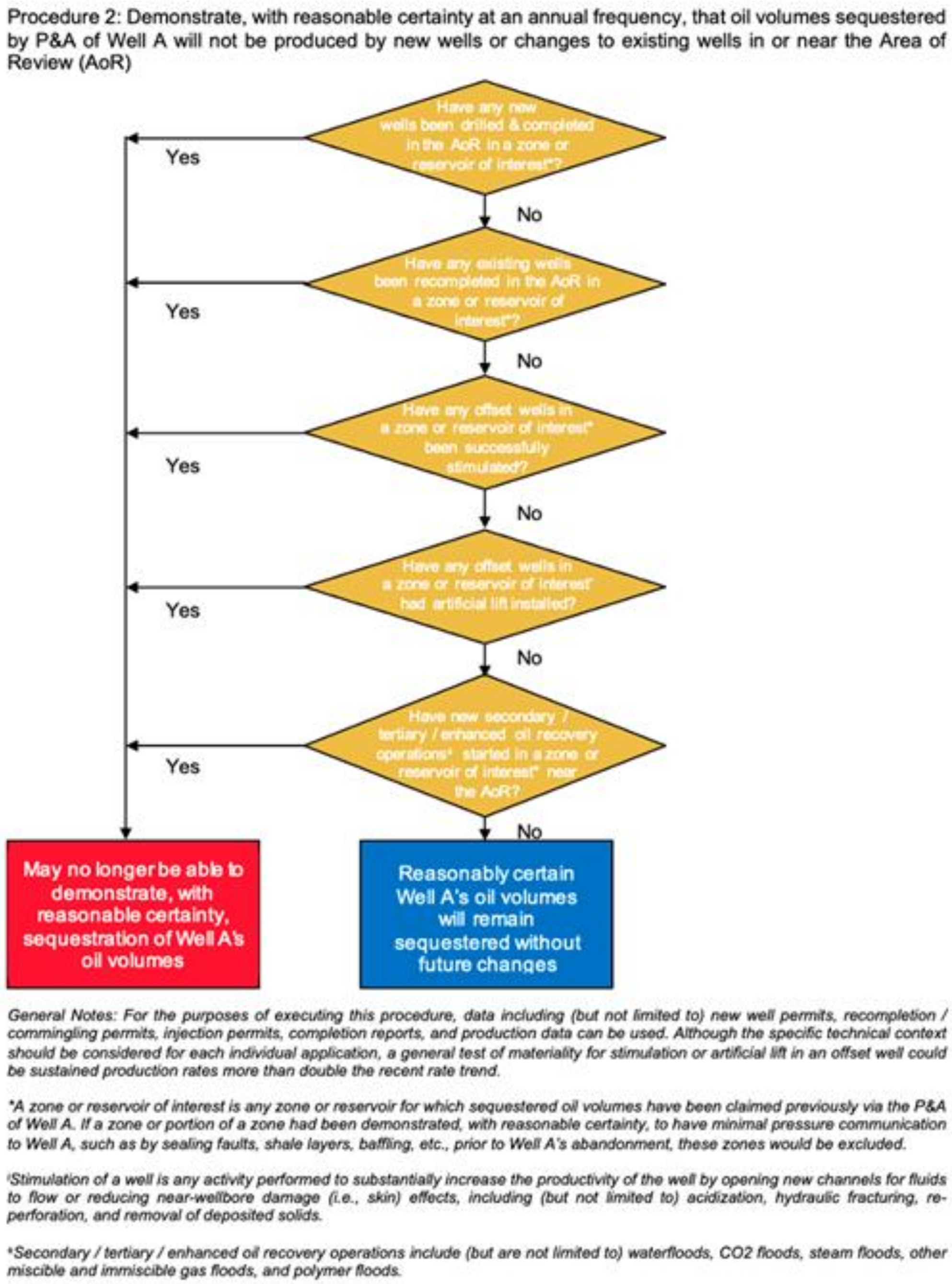


Figure D.4. Annual permanence monitoring procedure.

Every reporting period the project developer must determine whether a new well has been drilled within the AoR (as established by the PPEF) and whether existing wells undergo operational changes (e.g., idle to active). If there are no new wells, then the project will utilize the same permanence discount. However, if a new well is drilled, then the project developer must assess the risk of reservoir communication and take the applicable discount. Should the results of Figure D.4 indicate that new development will access sequestered reserves, the project is no longer eligible for crediting.

D.5 Permanence Deduction

After conducting the procedures outlined in this section, a leakage deduction must be applied to the economic reserves to account for the risk of reservoir communication. If it's determined to be reasonably certain Well B (non-project well) will not produce the oil volumes sequestered by P&A of Well A (project well), no permanence deduction is required.

If the project cannot demonstrate with reasonable certainty that there is a low risk of reservoir communication or the analysis determines there is a risk of communication, then the project must conduct the qualitative permanence review. A 5% deduction must be applied when the qualitative review analysis determines that low volumes of reserves may be recovered by a non-project well. Alternatively, if the analysis determines that medium volumes of reserves may be recovered by a non-project well, then a 20% discount is applied.

D.6 Uncertainty Adjustment

Wells that have low or medium data conclusiveness according to the qualitative review must apply an uncertainty adjustment. The uncertainty adjustment acknowledges from the ongoing research and the current need for more comprehensive data concerning the migration of reserves to adjacent wells and the long-term effectiveness of well plugs. A 5% and 1% must be applied to projects with low data conclusiveness and medium data conclusiveness, respectively. Projects with low data conclusiveness must apply a 5% uncertainty adjustment to the baseline emissions. It is important to note that this adjustment is not static; it shall be periodically updated in response to emerging research findings and the availability of new data. This dynamic approach ensures that the methodology remains responsible to evolving scientific understanding and data accuracy in the field.