Production Reserves Carbon Offset Protocol

Methodology for the generation of carbon credit offsets from the avoided GHG emissions of oil and gas proved developed reserves

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In November 2022 at COP27, world leaders stressed that this decade is pivotal for climate action – the imperative is to ensure global warming remains below 1.5ºC. Achieving a net-zero future by 2050, will require swift and committed action.

Climate specialists estimate that there are no more than 500 billion metric tons of CO_2e emissions remaining in Earth's carbon budget. Known fossil fuel reserves, the quantity of economically and technically producible hydrocarbons, total 2,900 billion tons if combusted unabated.[1] That's ~7x greater than the carbon budget, according to the Global Registry of Fossil Fuels.

In the near future, the most recent UNEP-led, collaborative Production Gap Report found that fossil fuel production is on track to be double what's needed for a 1.5ºC pathway by 2030. Climate scientists have concluded that some 60% of the world's oil and gas reserves and 90% of coal reserves must remain permanently in the ground — unextracted, unrefined, uncombusted.[2]

There are a variety of ways the world could reduce fossil fuel emissions and keep reserves in the ground, ranging from regulatory and policy interventions to market-based mechanisms. At ZeroSix, our focus is on tapping into buy-side demand in the voluntary carbon market (VCM), creating a financial incentive for oil and gas producers to retire wells early, permanently shut in the associated reserves, and convert the abandoned fossil reserves into high-quality carbon credits instead.

The ZeroSix protocol described in this technical document incorporates well-established standards and processes in the oil and gas industry (including building upon a foundation of stringent regulations from the U.S. SEC and other agencies). The protocol expands upon that foundation with further enhancements that strengthen the accuracy, additionality, and permanence claims associated with the carbon credits — all via an approach that also provides needed transparency and verifiability for VCM participants.

1. Purpose and Definition

1.1. The Protocol

The purpose of the Production Reserves Carbon Offset Protocol (protocol) is to:

- describe the process for determining the eligibility of proposed offset projects;
- quantify the amount of carbon emissions avoided;
- detail the validation needs of submitted data;
- describe the monitoring requirements of projects;
- outline the process of project execution; and,
- describe the verification requirements to generate carbon credits.

Projects must satisfy the criteria outlined by this protocol in order to qualify for credits from abated emissions associated with producible oil and gas volumes from existing operations. These volumes include any existing production that targets hydrocarbon reserves which would otherwise remain sequestered in the subsurface. The protocol outlines standards for execution and the monitoring of project operations to guarantee avoidance of forecast emissions.

This document is supported by industry technical documentation and standards referred to throughout the text and referenced in the following section 1.2.

1.2. Supporting Standards

This protocol is written to align with the latest standards and best practices regulating the relevant elements of the abatement project execution. The reserve volume calculations follow the long-established standards set forth by the United States Securities and Exchange Commission (SEC) Final Rule regulations for publicly traded oil and gas companies.[3,4,5]

The permanence requirements are tied to the current regulations of carbon sequestration, primarily the California Air Resource Board's (CARB) Carbon Capture and Storage (CCS) protocol for claiming compliant credits and the United States Environmental Protection Agency (EPA) Class VI permit requirements.[6,7]

The execution of plugging and abandonment of oil and gas wells is strictly controlled and certified by the respective state oil and gas regulatory agencies. The projects applying for abatement credits through this protocol must receive the appropriate permits and sign offs from these agencies in order to qualify for issuance. An example of state guidance for P&A can be found in section 1723 of the California Geologic Energy Management (CalGEM) Statutes and Regulations January 2022.[8] A similar regulatory permitting and verification process exists for land reclamation activities, following the permanent retirement of a production site.

The standards for execution of a project for carbon credit offset using this protocol align with the American Carbon Registry, Verra, and other existing registry standards, see Figure 1 below for a visualization of alignment. As the international community works to standardize the voluntary carbon market — per Article 6 of the Paris Agreement and further expounded upon at COP26 — this protocol will evolve to comply with relevant standards. This commitment to compliance will ensure the highest level of transparency and credibility of projects and tokens generated through the ZeroSix system.

The fundamental standards inherent in the ZeroSix design are the Core Carbon Principles (CCP), put forward by the Integrity Council for the Voluntary Carbon Market, and the guidance provided by the Voluntary Carbon Markets Integrity Initiative. The protocol is also designed to align with the International Carbon Reduction & Offset Alliance (ICROA) and will seek to become an accredited organization under these standards.

The Core Carbon Principles, developed with input from hundreds of organizations in the voluntary carbon market and launched in March 2023, set out fundamental principles for high-quality credits that create real, verifiable climate impact, based on the latest science and best practice.[9]

The 10 Core Carbon Principles are as follows:

1. Effective governance
2. Tracking
3. Transparency
4. Robust independent third-party validation and verification
5. Additionality
6. Permanence
7. Robust quantification of emission reductions and removals
8. No double counting
9. Sustainable development benefits and safeguards
10. Contribution toward net zero transition

The ZeroSix self-assessed alignment with these principles is shown in Figure 1.

	Project Eligibility Criteria	Project Boundary	Permanence			Project Execution Specifications	Carbon Offset Ownership Guidance	Additionality		Monitoring		Transparency				Quantification		Sustainable Development Goals	Contribute to Net Zero Transition
			Carbon Lockup	Legal Protection	Buffer Account			Tests	Intrinsic	Project Execution	Post-Execution	Independent 3rd Party Verification	Public Project Documentation	Immutable Tracking	Double Counting Protections	Robust Methodology	Uncertainity Evaluation		
ZeroSix Compliance	✓	✓ EPA Class VI	✓ EPA Class VI	✓ Legal Contract	✓ CARB	✓ State O&G Regulator	✓ Legal Contract	✓	✓ SEC	✓ State O&G Regulator	✓ State O&G Regulator	✓ State Licensing	✓ Immutable Blockchain	✓ Immutable Blockchain	✓ Immutable Blockchain	✓ SEC	✓ SEC	✓ UN SDG	✓
ICVCM Core Carbon Principle	✓	✓	6.	6.	✓ 6.	✓	✓	✓ 5.	5.	✓ 4.	✓ 6.	✓ 4.	✓ 3.	2.	✓ 8.	✓ 7.	✓ 7.	✓ 9.	✓ 10.
CARB LCFS	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓		✓	✓	✓		✓
ACR	✓	✓			✓	✓	✓	✓		✓	✓	✓			✓	✓	✓		✓

Figure 1: Protocol compliance against other standards.

1.3. Blockchain Implementation

This protocol is implemented using a blockchain-based decentralized application. A blockchain is a digital, immutable, and tamper-proof record of events ("ledger") replicated over multiple machines ("nodes") that uses a specific algorithm ("consensus algorithm") to update all records in a secure way.

This web-based tool utilizes smart contracts, which "are simple programs stored on a blockchain that run immutably and tamper-proof when predetermined conditions are met. They typically are used to automate the execution of an agreement so that all participants can be immediately certain of the outcome, without any intermediary's involvement or time loss. They can also automate a workflow, triggering the next action when conditions are met."[10] Executing the terms of the protocol in this way automates the actions that have historically been performed by the registries in a way that is immutable and tamper-proof; in other words, using the ZeroSix web-based tool ensures all steps are followed as intended with all proofs and digital signatures stored in a similar immutable and tamper-proof fashion. This removes the need for an intermediary to verify the status and validity of every carbon credit. This implementation allows for full transparency and consistent application of the protocol standards across all projects and removes a serious bottleneck in the global emission abatement initiative by improving on the conventional registry validation and verification process.[11]

For each project applying this protocol, the project owner and verifier will be required to upload supporting documentation. The document requirements have been established to vouchsafe the additionality and permanence characteristics of every project. All project files are stored immutably and tamper-proof on the InterPlanetary File System (IPFS), which is a distributed file storage system, thus guaranteeing public access to all documents for universal auditing and verification of the integrity of the associated carbon credits.

As an output of the decentralized digitalized protocol a digital token (ERC-1155) will be minted. This token has a fungible and non-fungible part which includes project and well specific information, such as the source well location, key dates, and a reference to the verification documentation.

1.4. Definitions

For purposes of this protocol, the following acronyms apply:

ADR – Abandonment, decommissioning, and reclamation
API – American Petroleum Institute
bbl - barrel
BLM – United States Bureau of Land Management
CARB – California Air Resources Board
CBM – Coalbed methane
CCP - ICVCM Core Carbon Principles
CCS - Carbon Capture and Sequestration
CiO – Gas consumed in operations
CO_2 - Carbon dioxide
CO_2e - Carbon dioxide equivalent
COGCC - Colorado Oil and Gas Conservation Commission
COP - Conference of Parties of the UNFCCC
DCA - Decline Curve Analysis
EDF Environmental Defence Fund
EPA – United States Environmental Protection Agency
EOR – Enhanced oil recovery
GHG – Greenhouse gas
GHV - Gas heating value
Gt - Metric gigaton
GWP - Global Warming Potential
ICROA - International Carbon Reduction & Offset Alliance
ICVCM - The Integrity Council for the Voluntary Carbon Market
IPCC – Intergovernmental Panel on Climate Change
IPFS - InterPlanetary File System
JOA - Joint Operating Agreement
LOE - Lease and operating expense
MMBtu – Million British Thermal Units
Mscf – Thousand of standard cubic feet
NGL – Natural gas liquids

NRI – Net royalty interest
P&A – Plug and abandon
PDNP - Proved Developed non-Producing
PDP - Proved Developed Producing
PIIP – Petroleum initially in place
SCADA – Supervisory control and data acquisition
SDG – United Nations Sustainable Development Goals
SEC – United States Securities and Exchange Commission
t – Metric ton
UNFCCC - United Nations Framework Convention on Climate Change
VVB - Validation and Verification Body
WI – Working interest

2. Eligibility

2.1. Types of Activities

This protocol applies to oil and gas production offset projects preventing the conversion of in-situ reserves into marketable commodities. This is achieved by executing the permanent abandonment of wellbores. The controlled mineral rights are then dedicated to protected non-recoverable resources through a legally binding declaration of restrictive covenants signed by the mineral owners, or an equally binding legal agreement. These actions prevent the future extraction of the designated resources, which are to be claimed for carbon credits.

2.2. Minimum Requirements

To be considered eligible under this protocol, a project owner must be able to:

1. Demonstrate that a conversion of project resources to a marketed commodity is imminent beyond a reasonable doubt by following the requirements establishing the project's economic reserves.
2. Verify — according to the standards of this protocol — the quality of the information submitted for the quantification of the project reserves.
3. Provide proof of resource ownership, mutual consent of royalty owners, or an equally robust mechanism for establishing a legal barrier to future extraction of hydrocarbons.
4. Demonstrate that participation in the ZeroSix project can be achieved while adhering to all relevant regulatory requirements.
5. Establish and verify the additionality of claimed carbon volumes by showing a clear baseline of business-as-usual production forecast.
6. Provide suitable justification for permanence of retired reserves. This is achieved by providing relevant geological, petrophysical, and fluid property analyses, in support of a post-execution monitoring program. Submission of regular reports over the course of the monitoring period of the project as designated by this protocol is envisaged.

Projects that adhere to these requirements are eligible for participation in the ZeroSix methodology.

2.3. Project Area

The current ZeroSix methodology is based on the United States' regulatory standards governing the execution of projects related to extraction activities, data reporting requirements for oil and gas producers, and standards used by the U.S. EPA for permitting Class VI Carbon Dioxide Injection projects.[7] The Class VI injection regulation is used as an analogue for documentary requirements used to establish subsurface permanence of mobile fluids. The project filings, validation and verification documents, regulatory compliance, and mineral rights unitization will be specific to each jurisdiction.

The project area is the region surrounding the geologically defined reservoir from which reserves are being produced. The project area is delineated using computational modeling or other best engineering practices that account for the physical and chemical properties of all phases of the produced fluids; and is based on available reservoir characterization, monitoring, and operational data. Specific project area boundaries are defined by the location of project wellbores and associated subsurface connected drainage volumes. Operations within and peripheral to this boundary will determine the permanence of the claimed emission volumes.

The project area:

1. Must be finalized by the conclusion of the full verification of project execution.
2. Must be consistent with the royalty ownership schedules of the project, and with the Declaration of Restrictive Covenants or the equally binding mechanism for establishing a legal barrier to future extraction of hydrocarbons.
3. All resources in the target reservoir must be converted to non-producible mineral resources as defined by this protocol.
4. Boundaries must be congruent with the specific subsurface connectivity structure according to the type of development, with the purpose of preventing resource migration outside the project area.
5. Must be determined according to best engineering practices for reservoir boundary definition.
6. Must be contiguous and fully inclusive of subsurface communication extent on a depletion time scale.
7. May not include mineral resources already designated as non-producible or off limits.

The project owner performs the following actions to delineate the project area and identify all wells that may require corrective action[7]:

1. Predict, using existing site characterization, monitoring, operational data, and/or computational modeling, the lateral and vertical connectivity of the formation fluids in the target reservoir. The evaluation must:
   a. Be based on detailed geologic data collected to characterize the retired production zone(s), confining zone(s), and any additional relevant zones.
   b. Account for any geologic heterogeneities, other discontinuities, data quality, and their possible impact on boundary predictions.
   c. Consider potential migration through faults, fractures, and artificial penetrations.
2. Identify all penetrations, including active and abandoned wells and underground mines, in the project area that may penetrate the reservoir(s).
3. Determine if any abandoned wells in the project area may have been plugged in a manner that might enable leakage of hydrocarbons.
4. Project owners must perform corrective action on all wells within the project area that are determined to be in need of corrective action using methods designed to prevent the movement of fluid out of the retired reservoir.

2.4. Stakeholder Obligations

Prior to project execution, the project owner must submit the working interest (WI) and mineral owner schedule of all open wells in the proposed project area. In addition, signed Declarations of Restrictive Covenants or an equally binding document must be submitted by the operator, representing the consent of all mineral owners to forgo hydrocarbon extraction rights from the target reservoir. Exceptions can be accommodated for mineral owners with missing contact data or who cannot be located to give consent, in such cases the project owner must meet the minimum standard for coverage as specified by the relevant state pooling and unitization requirements. The project owner will be responsible for acquiring the consent of their non-operating partners according to the terms of the Joint Operating Agreement (JOA).

2.5. Regulatory Compliance

The operator/owner/originator of the project must be in good standing with the relevant national and state regulatory agencies and to provide proof of a current operating license. There must be no existing state and federal government mandates for prudent recovery of oil and gas assets, which might impede efforts to shut in economic reserves for carbon crediting purposes; or the operator must provide written consent to pursue the proposed abandonment activity. The government may be compensated through royalty ownership of public resources (e.g., BLM and Tribal lands).

2.6. Additionality

The additionality test is intended to ensure that carbon offsets are an addition to reductions and/or removals that would have occurred in the absence of the project activity and without carbon market incentives. To be considered "additional," the project must demonstrate that the GHG emissions reductions and removals associated with an offset project are above and beyond the "business as usual" scenario.

Relative to alternative carbon emission offset projects, the proposal for retiring existing and future reserves must satisfy these 3 criteria. A compliant project demonstrates that it exceeds the 1) Regulatory Test: the proposed activity exceeds currently effective regulations, 2) Common Practice Test; goes beyond common practices in the oil and gas industry sector in the geographic region of operations, and 3) Implementation Barrier Test; faces one or more implementation barriers.[13]

2.6.1. Regulatory Test

1. Emission reductions achieved by foregoing expected production volumes must exceed those required by any applicable federal, Tribal, state, or local laws; regulations; ordinances; consent decrees; legal arrangements; or other legally binding mandates.
2. The project operator must have an active and valid operating license in the jurisdiction of the proposed project.
3. Legally binding mandates may include, but are not limited to, existing moratoriums on production from project land leases or mineral rights.
4. The legal requirements are satisfied if:
    a. Project activities are not legally required at the time of offset project commencement.
    b. Modeling of the project's baseline carbon stocks reflects all legal constraints and regulatory guidelines as required by SEC reserves reporting guidelines.
    c. Avoided production projects submit official documentation demonstrating that the type of operation activity proposed by the project is legally permissible, through valid activity permits.

2.6.2. Common Practice Test

The project must demonstrably depart or exceed common practice. Retirement of remaining economic production and reserves is not common practice and, therefore, with the proof of economically viable production, projects submitted under this protocol are deemed to have passed the common practice test.

2.6.3. Implementation Barriers Test

The proposed carbon offset project must fulfill at least one of three implementation barriers:

(a) Financial

Continued extraction of oil and gas volumes is deemed an economic venture, thus permanent retirement of these economic reserves faces strong financial barriers without the compensation through carbon credits or other means. The economic viability of targeted reserves is established through SEC reserves reporting standards, which must be adhered to in the quantification of carbon emission avoidance in this protocol (see Chapter 3).

(b) Technological

There are no new technological barriers to implementing the ZeroSix solution, which bolsters the case for broad industry implementation and rapid adoption. However, the value of the innovative ZeroSix blockchain enabled platform for the purpose of creating transparency and auditability of carbon emission abatement quantification and execution, is a new concept for the oil and gas sector. There is currently limited market penetration for this technology, but its relevance is the material reduction of GHG emissions.

(c) Institutional

Institutional barriers exist in the novelty of this approach and buy-in from regulators, mineral owners, and non-operating partners must be secured. Compensation through carbon credit values provides a strong incentive for project non-originating royalty owners to support the abandonment of productive reserves, rather than selling them for the purposes of refining and combustion, resulting in an ever-increasing global carbon debt.

2.7. Permanence

Projects must demonstrate permanence of avoided carbon emissions. The project owner/operator must submit a descriptive report prepared by a recognized professional organization that includes a compilation of project data (wireline logs, well tests, and structural/stratigraphic maps). In addition to the geologic permanence assessment, the project owner will need to secure legally binding contractual or legal protections against the future production of the retired resources. These protections, in addition to the digital platform mechanics, will provide assurance of:

1. Geologic Permanence: Through determination of target P&A candidate well drainage area calculations through geology, pressure transient analysis, reservoir modeling, material balance, or well interference case studies, and justification for the associated reserves remaining unproduced upon execution of the project.
2. Legal Permanence: Through proof of contractual amendment of ownership with permanent retirement of mineral extraction rights, through executed Declarations of Restrictive Covenants or equally binding legal protection against future extraction.
3. Operational Permanence: Through ongoing post-execution automated monitoring by the ZeroSix platform of state regulators for any new development permits being issued in proximity of project area.
4. Long Term Validity of Issued Credits: Through contribution to the ZeroSix buffer account funded through credit withholding to offset any detected reversals of reserve volumes claimed for the project credits.

The case for geologic permanence must be made from a technical perspective and will vary based on the type of resource operation of the submitted project. There are several broad cases of hydrocarbon extraction that are distinct in the properties of fluids, subsurface conditions, and/or development mechanics, which justify different approaches in determining permanence.

2.7.1. Conventional Resources

Conventional resources exist in porous and permeable rock under pressure equilibrium. The PIIP is trapped in discrete accumulations defined by a local geological structure, feature, and/or stratigraphic conditions. Each conventional accumulation is typically bounded by a down dip water contact, as its position is typically controlled by buoyancy of oil in water. The oil/gas is recovered through wellbores and typically requires minimal processing before transportation to market. The technical behavior of these systems is constrained with reasonable certainty and permanence can be achieved through the simultaneous abandonment of all wellbores produced from a discrete accumulation.

2.7.2. Unconventional Resources

Unconventional resources exist as petroleum accumulations that usually have a significant regional extent. They are not significantly affected by hydrodynamic influences (also referred to as a "continuous-type deposit"). Commonly, these accumulations are not defined structurally. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas/oil are subtypes of tight gas/oil, where the lithologies are predominantly shales or siltstones. These accumulations lack the primary connected permeability of conventional reservoirs and require subsurface stimulation to achieve economic viability.

Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders). The establishment of permanence of unconventional resources will vary based on the subsurface flow and extraction mechanisms involved.

Coalbed methane (CBM) – CBM gas is generated within coal seams and gas is stored via adsorption, meaning it is tied to the coal at a chemical level and does not flow freely. There are natural fracture networks in the coal formations called cleats, which may contain free gas, but may also contain water. The development of these resources generally involves induced fracking.

This type of production is exemplified by an early period of high-water production as the coal formation dewaters, and the gas rate increases, ultimately stabilizing once the dewatering of the stimulated formation and fracture network is complete. The gas rates are characterized by a shallow rate decline for extended periods of production. Reserves are extracted at a slow and steady pace of gas desorption from each producing well's fracture network in the target coal bed. It is this fracture network which conveys liberated gas molecules to the wellbore and subsequently to the surface.

The range of reserves' extraction is controlled by the extent of the fracture network and the disequilibrium between conditions in the fracture versus the coalbed. This disequilibrium can be influenced by a variety of factors including pressure differentials, partial pressures of gasses from concentration differences, and the percentage of water content. To establish permanence, it must be demonstrated that the target fracture network is not connected to and being produced by any offset fracture networks from nearby wells. This can be done via fluid property analysis, pressure tests in offset wells designed to determine wellbore interference to provide additional support for permanence models.

Basin-centered Gas, Tight Gas, and Tight Oil (e.g., Shale) – These resources exist in low permeability deposits and are extracted through stimulation by hydraulic fracturing. To establish permanence for induced fracture flow pathways, no pressure communication must exist with adjacent wellbores producing from the same target formation. This determination may be assessed regionally showing the largest distance of observed pressure communication between offset production wells. Only volumes outside this determined radius can be classified as permanent carbon emission avoidance.

Natural Bitumen (very high viscosity oil) and Oil Shale (kerogen) – Bitumen or heavy oil does not migrate without additional subsurface treatment, such as steam flooding to reduce viscosity and increase mobility; large volume water flooding; or through mechanical mining. Due to the fluid properties of this resource, permanence can be assured by discontinuing the enhanced recovery extraction activities (e.g., steam flooding or mining).

2.7.3. Technical Documentation

The following permanence guidelines are not exhaustive but will inform operators how to generate a credible permanence case for specific projects based on the technical details of production. The case for permanence must be documented in a comprehensive report, which will include the relevant information and data necessary to verify the credibility of the permanence of the credited reserves. The analogue of the EPA Class VI carbon dioxide injection permit requirements is used in the drafting of these requirements.[7] As the requirements for establishing permanence for an active injection plume at high pressures are significantly greater than establishing permanence for a static reservoir generally under low pressures, only requirements necessary to establish static permanence are used for validation of reserve retirement.

The submitted permanence report will include information on the geologic structure, hydrogeologic properties of the project reservoir, and past interventions through development. The report should also include a brief synopsis of the geologic history of the project site, and include the names, lithologies, and depths of the abandoned formation(s) and confining zone(s). The comprehensive exhibits must consist of the following:

1. The location, orientation, and properties of known or suspected faults and fractures that may act as reservoir boundaries or transect the confining zone(s) in the project area and a determination that they would not facilitate fluid migration;
2. Data on the depth, areal extent, thickness, including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;
3. Information on the seismicity history, including the presence and depth of seismic focal depths and a determination that the seismicity would not interfere with an at minimum 50-year containment; and
4. Geologic data, including surface/depth-structure maps and cross-sections illustrating regional geology, hydrogeology, and the geologic structure of the local area showing the presence and trends of folds, and whether the proposed storage site will be bounded by faults or other compartment features.

(a) Map

A map of the project area showing the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state- or EPA-approved subsurface clean-up sites, and deep subsurface mines. The map should also show faults, if known or suspected.[7]

1. Geological base-map (including geodetic projection parameters) that details the following:
    a. Lease boundaries.
    b. Project boundaries.
    c. Locations of all wells within project boundaries (XY or Lat/long format).
    d. If wells are horizontal or deviated, show lateral trajectory.
    e. Legend that designates status of all wells.
        i. Producing from project formation.
        ii. Producing from different formation.
        iii. Shut in and completed in project formation.
        iv. Shut in and completed in other formation.
        v. Plugged and abandoned.
        vi. Other wellbores penetrating project reservoir – but not P&A'd.
    f. Major (sealing) and minor (non-sealing) faults designated accordingly, transmissibility barriers and stratigraphic discontinuities.
        i. Above features that control project boundaries should be designated as such.
2. Isopach (thickness) map of the project formation with the same information listed above.
    a. Limits of isopach maps (pay termination) that define project boundaries should be marked as such.

(b) History Matching and Dynamic Data

Analysis of historical production and pressure data from the project formation showing any communication through faults, other adjacent formations, or with wells outside the project boundaries. Demonstrate and place into context for the dominant reservoir drive mechanism if such could either threaten the permanence of the sequestered reserves or could augment the case for permanence.

(c) Project Area Wellbore Inventory

A tabulation of all wells within the project area which penetrate the target reservoir(s). Such data must include a description of each well type, construction, date drilled, location, total depth, and record of plugging and/ or completion.

(d) Cross Sections

A combined structural/stratigraphic well-log cross section from as many wellbores as necessary to provide a representative illustration of structural trends relevant to the target reservoir. All wells should highlight the completed interval(s), designating the status of those completion intervals, e.g., open to production, shut-in, isolated, or plugged. The representative cross-sections should also show sealing faults that highlight pressure isolation.

(e) Wellbore Schematics

Wellbore schematics showing completion intervals of all wells, history of all mechanical events (workovers, recompletions, fish in hole, etc.), all perforations and status of perforations (e.g., open to production, shut-in, isolated, or plugged), and a schematic of proposed abandoned condition of wells in the project.

(f) Other Pertinent Information

Present any other tests, such as cement bond logs, interference tests, fluid analysis, well production tests, water salinity, tracer surveys, drainage radius calculations, material balance calculations, numerical simulation modeling, etc., that are pertinent to the establishment of the project as an isolated formation and area.

(g) Minimum Information Criteria

1. All analyses and tests to support the demonstration of permanence must be accurate, reproducible, and performed in accordance with established industry quality assurance standards.
2. Estimation techniques must be appropriate for each specific project operating environment as designated by industry best practices and EPA-certified test protocols must be used where available.
3. Any models must be appropriate for the specific project operation and tailored to the site conditions and fluid compositions.
4. Predictive models must be calibrated using existing information where sufficient data are available.
5. Probabilistic values and modeling assumptions must be used and disclosed whenever values are estimated based on known, historical information instead of site-specific measurements.

2.8. Abatement Period

Justification for the permanence of plugged and abandoned oil and gas reserves is that reserves remain indefinitely contained in their reservoir. Prior to containment, hydrocarbons either migrated from the source rock or, in the case of shale gas and oil, the reserves were generated in-situ. For the reserves to be exploited, significant investment must be committed to liberate the volumes. Should development of these reserves be halted, and the reservoir returned to its natural state (by effective P&A activity), the volumes will remain indefinitely contained.

The declaration of restrictive covenants with mineral owners (or an equally binding arrangement) will waive hydrocarbon extraction rights from project reservoirs for a minimum duration of 50 years or establish a reasonable expectation of a legal barrier to reserves extraction for the same duration. The stipulation does not preclude the mineral owner or operator from pursuing alternate uses of the reservoir pore space, such as carbon sequestration or geothermal energy development.

2.9. Buffer Account

The ZeroSix platform utilizes a buffer account to offset any unforeseen abatement reversal volumes to maintain the integrity of issued credits. Due to the engineered nature of this protocol and the slow rate of reserve extraction under business as usual, the amount withheld from the issued carbon credits has been set at 1%. This withholding has been deemed sufficient upon a thorough risk assessment across the full scope of projects that would be eligible to claim credits under this protocol.

The spectrum of risks considered here include:

1. Mineral ownership dispensation and potential impact on legally binding permanence.
2. Surface rights ownership dispensation and potential impact on legally binding permanence.
3. Technical risk of ongoing hydrocarbon leakage around surface wellhead post P&A.
4. Technical risk of claimed subsurface reserves being produced through offset wells.
5. Risk of current or future regulatory mandates for development and production of claimed hydrocarbon reserves.
6. Significant divergence in price of carbon credits and commodities price incentivizing future re-development of claimed reserves.
7. Potential for reservoir seal failure due to natural or artificial seismically induced activity through new fault creation or existing fault reactivation.

These are evaluated and quantified in relation to the potential impact on claimed carbon emission abatement reversals according to the standards set forth by the California Air Resource Board (CARB) and the carbon crediting industry best practices across existing registries. The scope of risks was informed by the current view of actuarial science on the insurability of carbon markets.[14]

2.10. Leakage

The risk of leakage for this protocol is the idea that shutting in producing wells and retiring the associated reserves will only result in production coming online outside of the project boundary to make up for the reduction in production. ZeroSix believes that demand side policies of the Paris Climate accord alone will result in leakage of emissions. This is due to the market mechanisms of supply and demand, and the resulting price distortions, which are taken advantage of by free-loader countries not participating in the agreement or not abiding by the emission reduction targets.

Multiple studies have demonstrated this phenomenon. For example, if there is a reduction in the demand for fossil fuels in one country due to emission caps, without reducing the supply of fuel, the price of these commodities will go down. Due to the international nature of the fossil fuel market, free-loading countries will be able to acquire and use more of these commodities at the reduced price, thus having no impact on global emissions. The only way to negate this leakage effect is to reduce the supply of fossil fuels in proportion to the reduced demand, thus eliminating the price distortions which would incentivize increased consumption in free-loader non-participating countries.[15,16]

The ZeroSix protocol creates a supply side mechanism for addressing emissions, starting with the least productive and most polluting sources first. Operators will be able to decide which production should be retired through the market mechanisms, comparing the value of abated carbon emissions to continued production. Reducing the supply alongside demand will prevent geographic leakage of emissions from both supply and demand side initiatives in participating countries abiding by emission reduction goals.

It is a daunting fact that the currently booked global reserves of hydrocarbons have a stock equivalent to 2,900 Gt CO_2e emissions.[1] If all of these are brought to market as is the current implication based on standard accounting principles of company valuations, there is a very low probability of meeting the ~500 Gt CO_2e emissions budget, set by the IPCC for keeping temperature rise to within 1.5 deg C. The mechanism proposed in this protocol permanently reduces the stock of global hydrocarbon reserves. There is also a multiplier effect from crediting only proved developed reserves and requiring the legal mandate of extraction from the associated reservoir, because this also reduced the stock of undeveloped reserves that could have potentially been brought to market in the future, as well as any volumes that would have been technically recoverable. Thus, by giving credit for volumes imminently slated for the market, the global reserve stock is reduced by an order of magnitude greater (i.e., 1,000 bbl PDP reserves credited, additional 10,000 bbl Undeveloped, Probable, and Possible reserves also permanently retired).

Beyond the systemic macro disincentives for leakage proposed, there is also a strong case at the project level due to several intrinsic mechanisms of this protocol. By crediting only proved developed reserves, operators must decommission existing operations and the associated infrastructure. By creating a financial incentive structure where operators are compensated for the abatement of immanent emissions associated with their hydrocarbon production rather than the market value of their product, they will preferentially retire the least economic and efficient operations, which are also the most polluting.[17] This also means that in order to return these volumes back to production, a significant capital investment for re-development of not only new wells, but also all associated surface infrastructure would be required. This is highly unlikely to occur due to the late life and relatively low economic viability of the production from these marginal fields, even when the required equipment is already present.

This protocol creates a means for operators to accelerate their energy transition initiatives by freeing locked up capital value in marginal polluting assets and allowing it to be reinvested in new energy sources, more efficient operations, or active carbon reduction initiatives such as CCS. This mechanism will act to deter leakage by redirecting invested capital from polluting fossil fuel projects to ones in line with the UN SDGs and creating more sustainable communities in line with global goals for the 21st century.

3. Quantification

Fossil fuels are the single largest source of GHG emissions. The lifecycle emissions from hydrocarbon production and use can be divided into three broad categories:

1. Upstream emissions: Emissions that occur during the production and extraction of hydrocarbons, including exploration, drilling, and transportation of oil and gas to the refinery or processing facility. Upstream emissions can include emissions from the use of fuels to power drilling equipment, as well as from the flaring or venting of natural gas.
2. Refining emissions: Emissions that occur during the refining of crude oils into usable products that include gasoline, diesel, and jet fuel. Refining emissions can include direct emissions from the refining process, as well as indirect emissions from the energy used to power the refineries.
3. Downstream emissions: Emissions that occur during the use of fossil fuel-based products, including the combustion of gasoline and diesel in vehicles, as well as the use of fossil fuel products for heating and electricity generation.

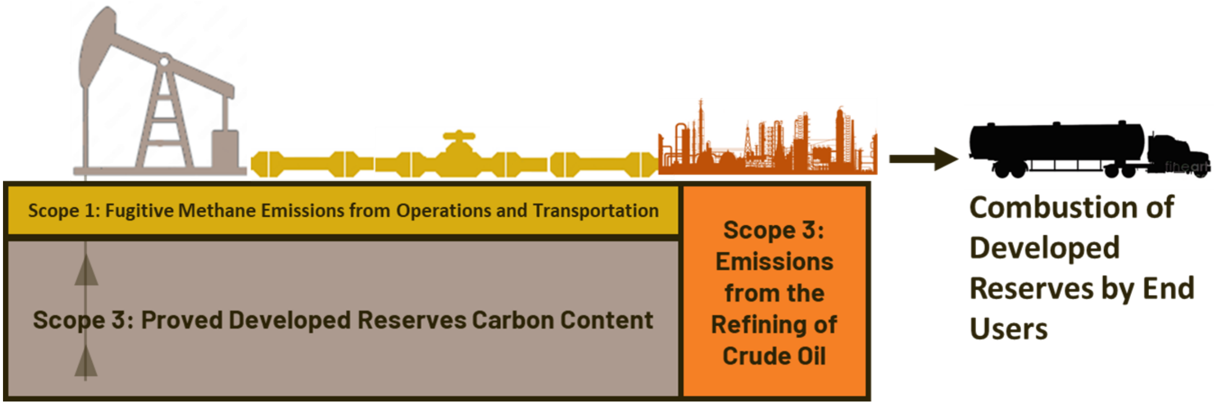

Figure 2: ZeroSix crediting boundaries.

The relative magnitude of these categories is shown in Table 1. These can be further categorized according to Scope 1, 2, or 3 relative to the party responsible for producing the hydrocarbon volumes.

1. Scope 1: Direct emissions that occur from sources owned or controlled by the operator, such as emissions from combustion of fossil fuels during production operations and emissions from flaring, venting, or fugitive leaks of methane gas.
2. Scope 2: These are indirect emissions that occur from the generation of purchased electricity, heating, and cooling that the operator consumes.
3. Scope 3: These are indirect emissions that occur from sources that are not owned or controlled by the operator, but that are associated with the produced fluid value chain. These include emissions from the combustion of the produced fluids by end-users.

The protocol enables project owners to recognize where the greatest reduction in emissions potentially resides. By targeting and crediting the largest contributing emission categories in the hydrocarbon fuel cycle, see Figure 2, project owners can implement the most effective emission reduction strategies. In order of magnitude, these are Scope 3: end use of produced oil, gas, and NGL reserves, Scope 3: refining of produced oil, and Scope 1: flaring, venting, and fugitive methane emissions.

$$GHG_{Total} = GHG_{oil} + GHG_{refining} + GHG_{gas} + GHG_{NGL}$$

$$GHG_{gas} = GHG_{combustion} + GHG_{vent}$$

Table 1: Comparative emissions across fuel cycles.

Fuel Cycle	Fuel Cycle Emissions	Scope 1	Scope 2	Scope 3
Downstream	65-80%			**End use of Produced Oil, Gas, and NGLs (Sec 3.1 & 3.2)**
Refining	5-15%			**Refining of Produced Oil (Sec 3.3)**
Upstream	15-20%	**Fugitive Methane Emissions (Sec 3.4)** **Flaring (Sec 3.4)** **Venting (Sec 3.4)** Onsite Combustion Operating Producing Facilites	Purchased Energy Materials Aquired	**Fugitive Methane during Transportation (Sec 3.4)** Transportation and Distribution Purchased Goods and Services Waste Capital Goods

3.1. Reserve Qualification

The US Securities and Exchange Commission (SEC) has established guidelines for regulating the calculation of hydrocarbon reserves. These are used by companies for their annual reporting obligations and to comply with investor and market transparency standards. The following have been established to ensure consistent definitions for both investors and market actors.[3,4,5] Project owners must engage a third party engineer qualified to prepare reserve reports according to SEC reserve quantification standards. From SEC requirements, the qualified person shall[5]:

1. Be a licensed professional engineer or a registered geologist with at least five years of relevant experience in the type of reservoir being evaluated.
2. Have experience in preparing reserve estimates or evaluating reserves that are relevant to the type of reservoir being evaluated.
3. Have familiarity with the geological and engineering principles and practices used in the industry for evaluating reserves.
4. Have a reasonable understanding of the legal and regulatory framework governing oil and gas operations.
5. Be independent of the company for which the report is being prepared, meaning that they have no direct financial interest in the company and are not an employee or officer of the company.
6. Be qualified to make engineering or geologic evaluations of the type of reserves being reported.

3.1.1. Eligible Volume Classification

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.[18] A further refinement (specific to a project's additionality criteria) is that only volumes designated as proved-developed reserves qualify as candidate volumes that currently satisfy additionality criteria according to this protocol. Standards of proved developed reserve volumes include two categories, developed producing and developed non-producing volumes.

Proved developed producing (PDP) reserves, are volumes expected to be recovered from wellbore intervals that are producing at the time of abatement project commencement.[3,4,5]

They are also determined to be economically recoverable under existing technical and commercial conditions with reasonable certainty using geoscience and engineering analysis.

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 a reasonable certainty.[3,4,5] A minor capital cost is defined as a lower expenditure than the cost of drilling and completing a new well. The quantity of incremental volumes must be supported by technical evidence with a high degree of confidence required for proved reserves categorization.

The incremental reserves associated with future workovers, treatments (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures may be classified as developed reserves if such projects have routinely been successful in analogous reservoirs or offset operations, and it meets the criteria of a minor cost.

In addition, reduction in backpressure from the surface gas gathering system through compression can increase the portion of in-place gas that can be economically produced and, thus, included in resource estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery may be included in developed reserves. To receive this designation, the cost to implement compression must meet the low-cost criteria. Alternatively, there must be a reasonable expectation that compression would be implemented by a third party. If the non-producing reserves meet the conditions above, they can be considered for carbon credits based on the consistent standards as the producing volumes.

Reserves from potential enhanced oil recovery (EOR) projects are not covered by the ZeroSix protocol. These projects do not meet the minor-cost criteria and increase the deterministic uncertainty associated with quantifying the volume of avoided emissions.

3.1.2. Recoverable Reserve Volumes

The performance-based analytical procedure for estimating recoverable quantities shall be applied for PDP reserves, however, high confidence volumetrically determined reserves can be used for PDNP where historical performance data may not be available. This approach can 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 two most widely used are the a) material balance and b) production performance analysis methods.

a) Material Balance

Material balance methods used to estimate recoverable quantities involve the analysis of pressure depletion as reservoir fluid is withdrawn. In ideal situations — such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks, and where sufficient and high-quality pressure data are available — material balance may provide highly reliable estimates of ultimate recovery at various abandonment pressures. In complex situations — such as those involving aquifer water influx, compartmentalization, multiphase behavior, and multi-layered or low-permeability reservoirs, shales or Coalbed Methane (CBM) — material balance estimates alone may provide inconclusive results. Project evaluation must accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

Reservoir simulation can be considered a more rigorous form of material balance analysis. While such modeling can be a reliable predictor of reservoir behavior, the origin and therefore credibility of input data including rock properties, reservoir geometry, relative permeability functions, fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

b) Production Performance Analysis

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, provide useful information to predict ultimate recoverable volumes. Prior to the full production rate decline profile becoming apparent in well history, trends in performance indicators such as gas/oil ratio, water/oil ratio, condensate/gas ratio, and bottomhole or flowing pressures, in combination with knowledge of the reservoir drive mechanism, can be extrapolated to the economic limit to estimate reserves. 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 must 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. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the other factors (e.g., operational, regulatory, contractual) that impact the abandonment rate. Such uncertainties should be reflected in the reserve's quantification.

In very low-permeability reservoirs (e.g., unconventional reservoirs), care should be taken in the production performance analyses because the lengthy period of transient flow and complex production physics can make analyses quite difficult.

3.1.3. Uncertainty

Uncertainty and risk are inherent with quantification of subsurface volumes. These can be summarized into three categories:

1. The total hydrocarbon and associated resulting emissions remaining within the accumulation.
2. The technical uncertainty in the portion of the total hydrocarbons that can be recovered by the project proposed for emission avoidance considering the technology applied.
3. Known variations in the commercial terms that may impact the recoverable volumes which can be delivered to market and result in emissions (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) as part of the project scope.

Late-life PDP reserve volumes with a well established operational history are typically estimated deterministically, while PDP volumes with a history of erratic production and PDNP volumes can be better addressed through a probabilistic estimate; the probabilistic approach can manage the range of uncertainty . In such a case, volumes are calculated with a 90% confidence of exceedance and translate to volumes expected to be recovered (applicable for carbon credit through avoidance) that will equal or surpass the stated P90 estimate. The deterministic approach for volume calculation can be more subjective, but by incorporating the qualitative expression "reasonable certainty," it is intended to convey a degree of confidence that the quantities will be recovered.

Project reserves will be estimated using the above uncertainty evaluation methods, which incorporate subsurface analyses together with technical constraints related to the operation of wells and facilities. Additional commercial criteria would then be applied to the technically recoverable reserve volume forecasts to estimate the true volume of additional abated emissions. These commercial criteria may include but are not limited to operating expenses, future commodity price, realized price differentials, royalty structure, tax burden, and lease or license duration.

3.1.4. Price Determination

Proved reserves must be economic in order to meet operational business requirements. In addition, proved reserves must satisfy the economic threshold to comply with additionality criteria to be considered for carbon credits as part of an emissions abatement program. The key metric for profitability assessment is the future looking commodity price over the expected life of the asset, which can be a significant variable. To establish a common evaluation, the SEC has standardized the reserve price forecasting methodology by using an average 12-month historical price on a go-forward basis. This standard is to be applied to all reserve determinations for the purposes of claiming emissions avoidance carbon credits.

The 12-month period starting from the most recent practical month prior to the issuance of the applicable reserve report shall be applied using an unweighted arithmetic average of the first day-of-the-month price for each month within such period. For example, the relevant 12-month period for a reserve report issued on December 31 would span from the first day of January through the first day of December of that year.[3,4,5]

3.1.5. Assessment of Economic Viability

Economic assessments are conducted on a project basis and are based on the operator's view of future conditions. Economic conditions include, but are not limited to, assumptions of general financial conditions (e.g., costs, prices, fiscal terms, taxes); organization capabilities; and marketing, legal, environmental, social, and governmental factors.[3,4,5] Project economic viability may be assessed based on cash flow analysis. Factors that may influence long-term viability and, hence, additionality of the avoided carbon emissions, such as contractual or political risks, should be recognized and addressed in the project reserve report.

(a) Net-Cash Flow Evaluation

Project reserve economics are based on estimates of future production and net-cash flow (as of an effective date), as reported in a third-party reserve report. This documentation will be uploaded to the ZeroSix platform in support of the retired carbon volume. The third-party reserve reports are industry standardized documents, prepared by state licensed engineers.

Project owners provide the following data in the third-party reserves report lease operating statement (LOS) and financial model support document:

1. Historical and forecast prices for produced gas ($/MMBTU), oil ($/BBL), and condensate ($/BBL), as well as a description of any existing sales contracts.
2. Any cost or price escalation schedules and rates if stipulated in existing contracts, otherwise they are not considered under SEC standards.

3. Historical and forecast operating expenses and supporting cost model including fixed and variable costs, fuel and gas shrinkage volumes, and any plans for cost reduction.
4. Lease and operating expense (LOE) statements, including water disposal and transportation costs.
5. Ad valorem tax rates and/or other tax application-regimes as well as any special production tax exemptions.
6. Transportation, processing & handling fees.
7. Planned capital expenditures for development or workovers associated with PDNP reserves, as well as abandonment, decommissioning, and restoration (ADR) liability for all project wells.
8. Ownership interest data, including working interest, net revenue interest, reversion interest, and pay-out balances at the effective date.
9. Contract, lease, or concession expiration dates.

(b) Economic Criteria

The forecast project-production volumes are deemed economic when the revenue attributable to the project owner's interest from production exceeds the cost of operation. The abandonment, decommissioning, and restoration costs are excluded from the economically producible determination.

Economic viability is tested by evaluating cash flow estimates based on the forecast economic conditions including operating costs, product price schedules, realized price differentials, and other relevant market factors. The forecast should reflect life-cycle assumptions applicable throughout the duration of the production operation. Inflation, deflation, or market escalations may be made to forecast costs and revenues. Forecasts should be based on current economic conditions and are estimated using an average of prices and costs over the preceding 12-month period, as per SEC guidelines. If a significant departure has occurred within this time, the use of a shorter timeframe that reflects the step change must be documented. All costs are included in the project economic analysis unless specifically excluded by contractual terms.

Figure 3 illustrates a net cash flow profile for a project. The project's economic production is truncated at the economic limit when the maximum cumulative net cash flow is achieved, before consideration of abandonment, decommissioning and reclamation (ADR).

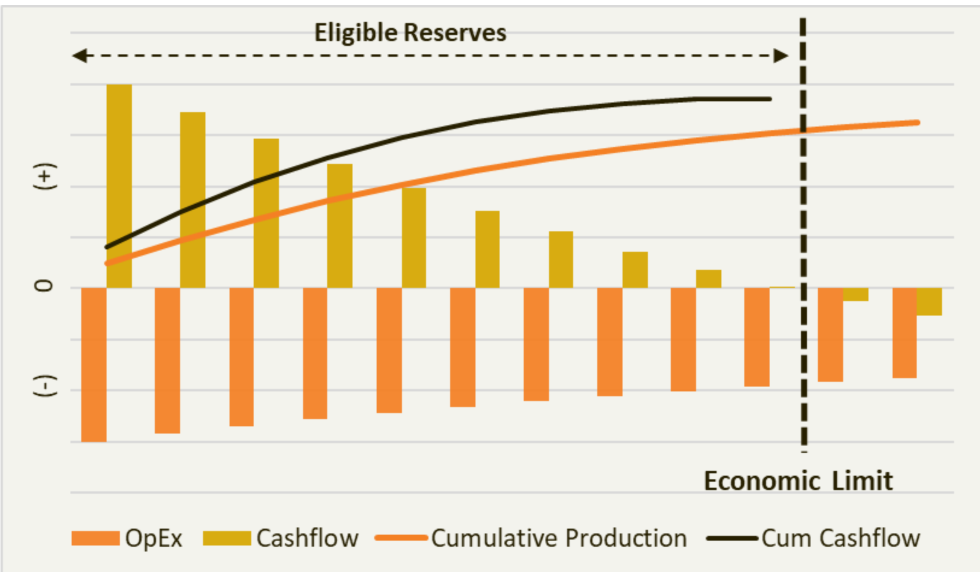

Figure 3: Eligible reserves economic limit.

(c) Economic Limit

The economic limit is defined as the production rate at the time when the maximum cumulative net-cash flow occurs for a project. The production volumes credited toward avoided emissions, are truncated at the end of the month in which either the technical, license, or economic limit is reached, whichever occurs first. In this evaluation, operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those costs that will be eliminated if project production ceases).

Operating costs should include fixed property-specific overhead charges if these are incremental costs attributable to the project, as well as any production and property taxes. The calculation of the economic limit should exclude depreciation, ADR costs, income tax, and any overhead not required to operate the property. Interim negative project net cash flows may be accommodated in periods of low product prices or significant operational adjustments provided that the longer-term cumulative net cash flow forecast determined from the effective date exceeds the cumulative net cash flow during periods of negative economic operation. These periods of negative cash flow will qualify as reserves if the following positive periods more than offset the negative. No sub-economic production beyond maximum future cumulative net income can be considered as reserves for the purposes of crediting avoided emissions.

3.1.6. Production Facilities

Each project must satisfy the basic needs for facilities required to maintain economic production for the foreseeable future, with no expectation of major expenditures or upgrades for at least 12 months. There must be sufficient facility infrastructure to allow for reliable export to market or disposal of all production components from project wells, consistent with the forecasted volume profile of the proved reserves.

3.1.7. Reserves Volume Documentation

The project owner must submit the following three documents to the ZeroSix platform with the hydrocarbon volume information consistent with the third-party reserves report. Once these documents are accepted by the third-party verifier for consistency with the claimed carbon credit amount, they will be immutably stored on the IPFS as a permanent record validating the amount of emissions abated and removed by the project.

Project Reserves Report - Field Monthly Forecast providing the monthly amount of hydrocarbons forecasted to be produced by all the project wells combined, abiding by all the rules and regulations specified in this protocol.

Project Reserves Report - Well Level Volumes providing total recoverable volume as a single value per well for each credited stream of hydrocarbons or other emissions.

The project owner must submit third party reserves report historical production and forecast plots in a pdf document for the purpose of verifying well forecasts and remaining recoverable volumes against historical trends, clearly showing:

1. Rate time plots for all production streams submitted for carbon offsets under this protocol at the well level.
2. Enough production history on a monthly basis to clearly justify the forecasted trend, but not less than 12 months.

3. Forecast must be shown from the project as of date, through to the economic limit of each well plus one year.
4. Decline parameters, including initial rate, b-factor, initial and terminal decline rates, and cut off rate for every forecast segment.

3.2. Carbon Stock of Reserves

Carbon-content quantification of reserves begins with fluid characterization at a specified reference point in the production flow-chain. The reference point is a defined location within a petroleum extraction and processing operation where the produced quantities are measured. This is typically the point of sale or where custody is transferred to the midstream or downstream operations. This point is envisaged to correspond with the point at which combustion of the product and emission of the associated GHGs by the end users occurs. Hence avoided emissions of the reserves will be determined in terms of quantities that would be crossing this point over the period of economic producibility under the defined operating assumptions.

It is important to have a good understanding of how historical production quantities were reported. Sales quantities are equal to raw production less non-sales quantities (those quantities produced at the wellhead but not available for sales). Non-sales quantities include petroleum consumed as fuel, flared, or lost in processing; these would also be credited for avoided conversion following a successful permanent abandonment of the designated production. The full sum of avoided emissions is the aggregation of non-sale volumes and sales.

Sales quantities may need to be adjusted to exclude components added in processing but not derived directly from project well production. Total well production measurements are necessary and form the foundation of many engineering calculations (e.g., material balance and production performance analysis) based on total reservoir voidage. Additives to the production stream for various reasons, such as diluents to enhance flow properties, are excluded from avoided emissions resources. Consumed in operations (CiO) and flared volumes are typically not included in standard reserve reports but need to be included in the avoided emissions calculation; this is generally encompassed in the gas shrinkage volume and is added back into volume determination.

3.2.1. Carbon Emissions Intensity

Once the remaining technically and economically recoverable volumes have been established for oil, gas, and natural gas liquids (NGLs), their respective volumetric carbon intensity is established. The carbon intensity is determined by the chemical composition of each fluid and is directly calibrated by standard fluid property field measurements.

Gas phase carbon content is determined using the emissions constant for methane, 52.91 kg CO_2/MMBtu, which constitutes the majority of the gas phase following the well site phase separation process.[19] The emissions factor is adjusted by the gas heating value (GHV); for pure methane it is 1.00 MMBtu/Mscf and, in some cases it may be adjusted upward to account for the presence of heavier gas components such as ethane, propane, butane, and pentane+. The factor can also be lower if there are non-reactive contaminants such as nitrogen or CO_2 present. The heating factor is to be submitted by the project owner and verified by submission of a recent gas analysis report from a third party gas analysis laboratory.

$$\boldsymbol{GHG_{combustion} = 52.91 * GHV * (1 - FE) * V_{gas}}$$

$$FE = Fugitive\ Methane\ Emissions\ [\%]$$

The NGL emission factor is also verified from the gas analysis report, where the molecular weight percentage of ethane, propane, butane, and pentane+ is reported. The liquid fractions and the corresponding component emission constants as reported in the 2022 EPA Fuel Emission-Factors document can be used to determine the total emissions per barrel of natural gas liquids from the proposed project, as shown in Table 2.[19]

$$GHG_{NGL} = [x_{ethane} * 170.1 + x_{propane} * 240.24 + x_{butane} * 280.14 + x_{pentane+} * 323.4] * V_{NGL}$$

Table 2: NGL emission intensity.

NGL Component Emission Intensity		
	kg CO2/gal	kg C02/bbl
Ethane	4.05	170.1
Propane	5.72	240.24
Butane	6.67	280.14
Pentane+	7.7	323.4

The CO_2 emissions factor for oils is variable due to the unique composition of hydrocarbons. The variability reflects organic geochemistry, depositional environment, and subsequent thermal history which could markedly impact temporal kerogen maturation. The API gravity (a measure of the density) of the oil phase is correlated with the length of its component carbon chains, the longer the carbon chains, the heavier the oil, and the larger the CO_2 emissions factor upon refining and use.

Figure 4 illustrates representative fractions of refined products from crude oils of different API measurements.[20] Emission factors of different components shown in Table 3 and their fractions were used to determine representative kg CO_2/barrel emissions at each of the represented API gravities shown in Figure 5.[19] The best-fit line with a strong R factor of 0.9828 is the relationship used to calculate CO_2 emissions and equitable issued carbon credits for the oil phase based on API. This measurement is verified by a submission of recent oil sale receipts issued by a third party offtake operator which has the API gravity of the oil clearly visible.

$$GHG_{oil} = [-0.9656 * {}^{\circ}API + 458.95] * V_{oil}$$

The CO_2 equivalent mass of avoided emissions is determined by combining the proved developed recoverable volumes of each production phase and the associated carbon content described in this section. The prevented scope 3 emissions represent the early retirement of reserves which prevents downstream combustion by end users.

Table 3: Crude oil refined product emission intensity.

Crude Oil Refined Products Emission Intensity			
	kg CO2/MMBtu	kg CO2/gal	kg CO2/bbl
Butanes and lighter	63.04	5.8	243.6
Gasoline components	71.35	8.78	368.76
Naphtha	72.38	10.26	430.92
Kerosene	73.19	9.88	414.96
Distillate	74.14	10.19	427.98
Heavy gas oil	74.00	10.21	428.82
Residual fuel oil	75.09	11.24	472.08

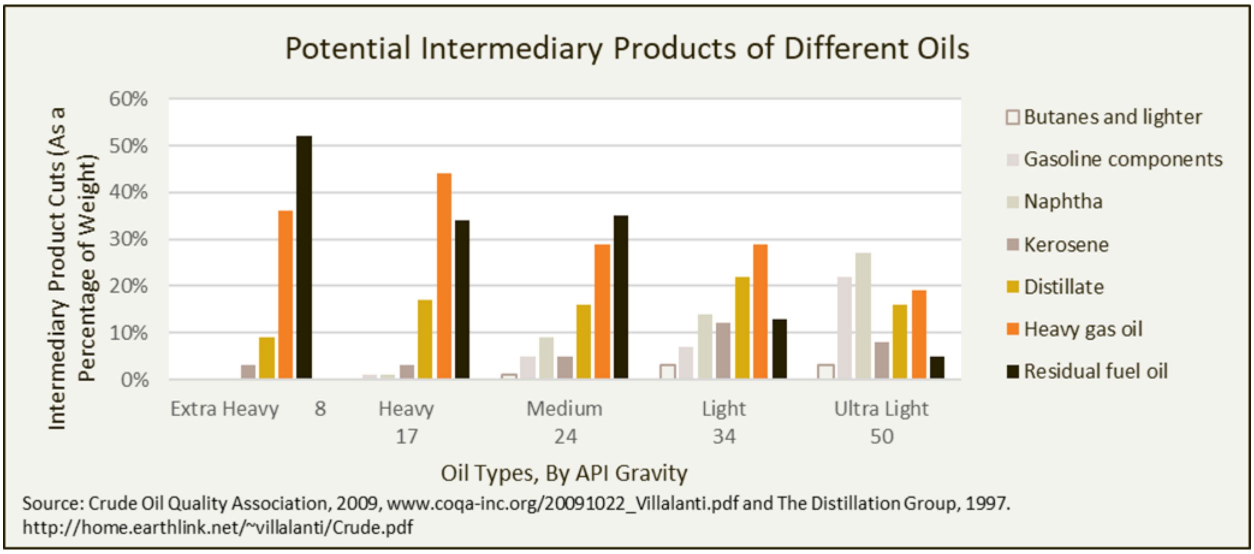

Figure 4: Intermediary products of different oils.

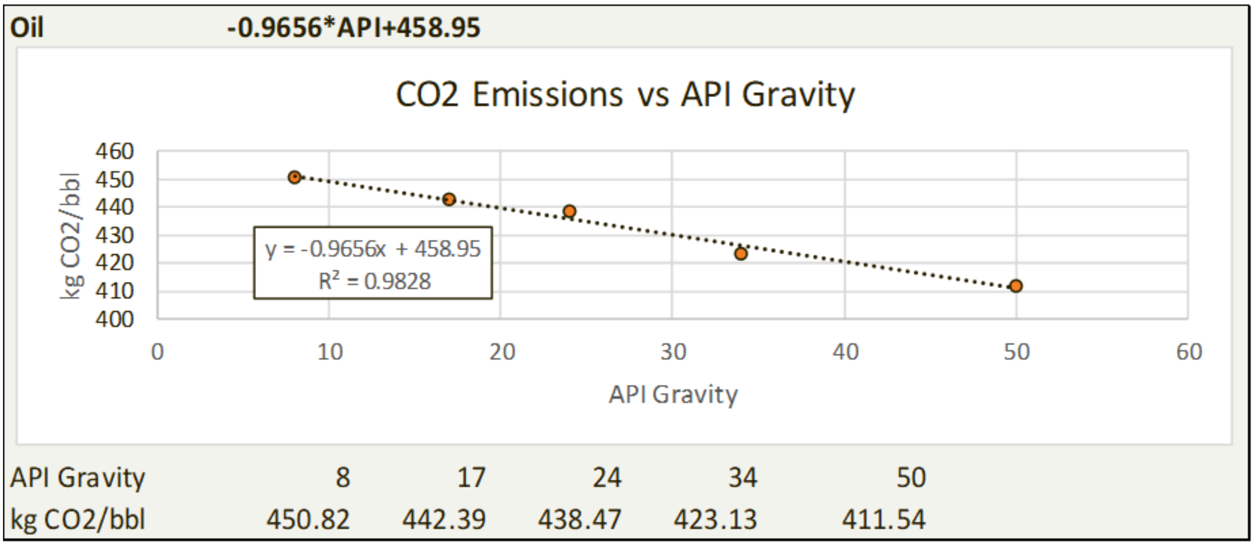

Figure 5: Resulting CO_2 emissions based on API gravity.

3.3. Downstream Scope 3 Emissions Avoidance

In addition to the avoided emissions from combustion of the produced oil, there are fuel cycle emissions originating from the oil and gas transportation and processing. By not bringing these resources to market as final refined products, additional emissions avoidance is captured. Many of the fuel-cycle emissions have a high degree of variability based on the technical nature of the specific projects and the geographic location of the operations, which may significantly impact the associated energy and emissions of the production operations and transportation to market.

In comparison, direct emissions from refining crude oil into specific products (summarized in Figure 6), are of more significance. Brandt, et.al. propose a linear relationship between crude oil gravity and refining GHG emissions, which is here utilized to provide the basis for associated credits.[21] The emissions are accounted for in the crediting calculation since they are parameterised by a standardized property of the crude oil, rather than project specific variables. Because of the high degree of confidence of these scope 3 emissions, their inclusion is merited and therefore credited to the project owner upon successful project execution.

$$GHG_{refining} = [-0.77 * {}^{\circ}API + 86.39] * V_{oil}$$

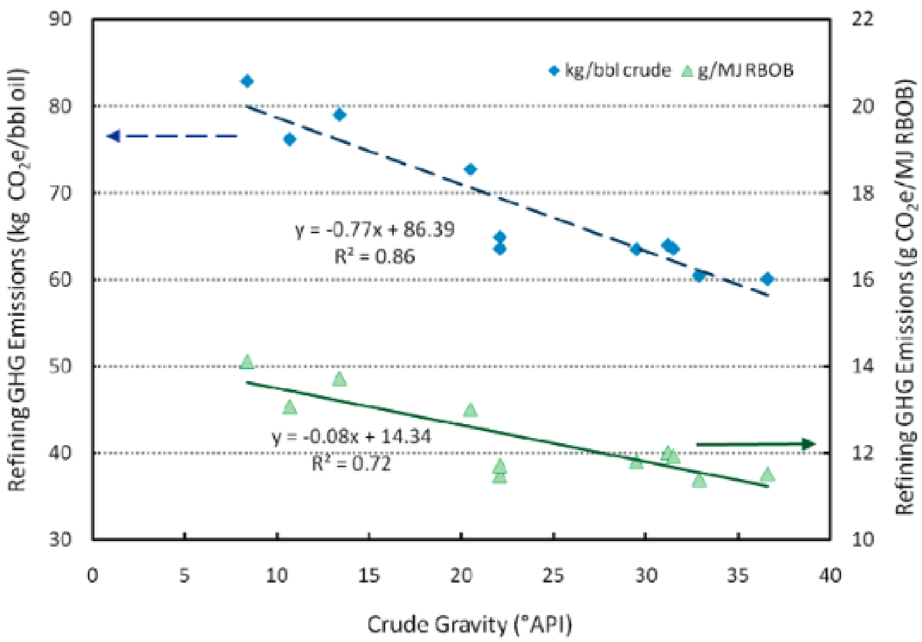

Figure 6: Refining GHG emissions based on API gravity.

3.4. Scope 1 Fugitive Methane Emissions

In addition to the scope 3 CO_2 emissions eliminated by preventing the combustion of gas reserves, there is also an associated abatement of methane release from production systems and/or leaks during transportation to the downstream market. The published results of the Environmental Defence Fund (EDF 2012-2018) study concluded that the industry supply chain rate of fugitive methane emissions is 2.3% of total domestic production.[22] The research engaged 140 independent experts, from 40 different research institutions, across 16 rigorously executed projects, with support from 50 companies.

The abated methane leakage from operations and transport of produced gas are credited to the project owner on a CO_2 equivalent basis, using the 100-year GWP. The credit for these abated emissions is included, applying the average 2.3% of the verified remaining gas reserves. The early retirement of older, marginally economic wells mainly targeted by the incentives of this methodology cumulatively only account for 6% of US domestic production, but account for approximately 50% of fugitive methane emissions. This translates to a normalized loss rate of ~10%.[23] Typical sources of operation methane leaks include:

- Fugitive equipment leaks
- Process venting
- Evaporation losses
- Disposal of waste gas stream (i.e., venting or flaring)
- Accidents and equipment failures

Due to the greater impact of methane on global warming, upon the successful abatement of these scope 1 emissions, the 2.3% of verified gas reserves shall be credited on a CO_2 equivalent basis. According to the latest IPCC AR6 report, the CO_2 equivalent global warming potential (GWP) of methane on a 100 year basis is 27.9 times greater than that of CO_2, thus for purposes of carbon credits, the fugitive methane emissions as a percentage of gas reserves is evaluated at 1,476.19 kg CO_2 equivalent/Mscf.[24]

$$GHG_{vent} = 52.91 * GHV * GWP_{CH_4} * FE * V_{gas}$$

4. Validation

4.1. Project Eligibility

For a project to be protocol compliant the operator must satisfy the following minimum requirements with documentary validation:

1. A submission of operator license issued by the respective state regulator, and confirmation of an operating record without pending investigations or inquiries.
2. Economically validated hydrocarbon volumes, (those reserves that would be produced and sold without the benefit of the carbon credits mechanism). This will be verified by an accredited engineer working under the third-party auditor, and who will certify the reserves report. This report will validate all claimed economic volumes based on standard regulatory parameters, and thus can be reasonably expected to be produced, and are considered additional emissions avoided due to the granting of carbon credits.
3. A copy of the documents outlining the legal framework, designating target reserves as off limits for production for a minimum, 50 years. This contract will be tied to the mineral ownership title, thus the current and any future mineral owner forgoes the right to extract the targeted resources in exchange for just compensation proportional to their royalty claim or other compensation as negotiated with the project operator. This will legally bind the permanence of the avoided emissions by preventing future targeted development of the impacted resources.
4. A submission of documentation validating the project owner's best technical justification that oil and gas volumes claimed for carbon credit issuance will remain in the reservoir. These volumes will not migrate to any offset wells or to the surface through any open flow conduits. This claim will be validated through submission of a comprehensive technical report corroborating such a claim, and will be independently verified by a licensed third-party technical body.

4.2. SEC Proved Reserves

The volume of reserves to be credited must meet requirements and standards as set forth by the Securities and Exchange Commission, validated by existing industry mechanisms as follows:

1. Third-party reserve report prepared by a qualified person as described in section 3.1, verified by an accredited engineer, and conforming to industry standards as laid out by the SEC.[3,4,5,18] The reserve reporting body will validate results independently of the project owner, thus mitigating any conflict of interest.
2. The eligible volumes for carbon credits will be scrutinized for consistency against third party reserve reports.
3. Well-level volumes will be submitted which must be consistent with the total volumes claimed. Internal consistency of the submission in different forms and independently verified by existing accredited auditing entities will serve as data quality validation.

4.3. Carbon Content

The carbon content of the credited volumes is representative of the geochemistry and physical properties of the hydrocarbons. These are documented using standard industry documentation issued for producing assets. The validation of this data relies on established industry reporting practices and regulation:

- Produced oil API gravity measurements are validated by the oil sales receipts from historical production.
- Produced gas heating value and NGL composition are validated by a gas analysis report from a credible testing facility. These reports are critical for safe operation of production and transportation facilities, and composition of marketed gas is often stipulated in contracts between the producer and mid-stream operator, thus the quality of the report data is largely enforced by operation contracts.

4.4. Data Quality

The data quality assurance for volumetric quantification in this protocol is provided by the legal obligations of operators to submit accurate data to regulators monthly, as well as the board-certified engineer's legal obligation to uphold industry reserve reporting standards when validating reserve reports. Third-party reserve reports provide inherent quality assurance. They are sourced from a trusted, independent organization that is accountable to the SEC.

The carbon content documentation from the midstream gas analysis report is deemed trustworthy due to pipeline safety standards requirements. The accuracy of accounting for the quantity of gas being sold is of paramount importance. The API gravity measurement on oil sales receipts must be accurate for logistics purposes, thus it is in the interest of the off-take company–as well as the producer–to have an accurate fluid characterization so that facilities and transportation equipment can be appropriately maintained.

5. Execution

The execution of the abandonment and reclamation activity will be specific to each project and must conform to the regulatory guidelines of the jurisdiction. The process flow is described, relative to regulatory obligations and verification submission requirements.

The platform also requires documented proof of appropriate notification and provision of information to such state, local, and Tribal authorities that have authority over drilling activities. This enables such authorities to impose appropriate restrictions on subsequent drilling activities that may penetrate the injection and confining zone(s).

5.1. Plugging and Abandonment (P&A) Regulatory Process

The plugging and abandonment process varies by state and is specified by the respective resource governance organizations. The correct execution of this procedure is independently verified by the state oil and gas regulatory bodies. As part of the project submission process, the project operator is required to submit a P&A permit issued by the state regulator for each well intended to be abandoned according to the project permanence documentation.

The general process to plug and abandon a wellbore is described:

1. Make decision to P&A well.
2. Identify water strata and hydrocarbon production horizons to ensure cement plugs are set to isolate each.
3. Notify surface landowners.
4. File a P&A plan with the state (e.g., Colorado Oil and Gas Conservation Commission – COGCC in Colorado) regulatory agencies.
5. Agencies may provide feedback and edits, and ultimately grant approval and plan permits for a specific period.
6. Find a state approved cementer.
7. Secure cement supply and rig for a specific date within the valid permit period.
8. Upon scheduling the operation for a specific date, inform regulatory agencies at least 48 hours prior to start of operations; they will engage an observer to witness plugging execution.
9. Project owner should follow all operations and requirements set forth by the regulator for all conditions to safely and permanently abandon the wellbore according to the approved and permitted execution plan.
10. State or federal observers witnessing the plan execution certifies the P&A if all criteria are attained.

5.2. Land Reclamation Regulatory Process

In projects where all activity is retired, the operator must perform a full site-reclamation program according to the guidelines of the state regulator. The remediation and reclamation will be documented in the final report.

6. Monitoring

The project owner must submit a monitoring plan designed to validate the proper reclamation of the project area and the permanence of the reserves. The primary means of determining the permanence of the claimed reserves is to monitor any new activity for potential development after verifying that all extraction activity has been abandoned per the project plan.

Minimum monitoring requirements:

1. Observation of production and development activity from offset operators that might be targeting or impact credited reserve volumes (see Section 6.1).
2. Progress of land reclamation (see Section 6.2).

6.1. Activity Monitoring of Project Area

The project owner shall monitor the absence of new extraction activity in the project area for the duration consistent with requirements for land reclamation by the state regulator. It shall also validate that no new permits for resource extraction within project boundaries, by project operator, landowner, or any other operator have been submitted. Lack of activity can be proven by submitting a list of permit filings for the project county from the state oil and gas regulator, with no new submissions on any leases within the project boundary. Should the county list show permitting activity for any project lease, the project must answer the following three questions:

1. Is the permit still active and valid?
2. Is the permit location inside the specific project boundary?
3. Will the activity, if permitted, have any tangible interaction with the subsurface zones targeted by the project (i.e., proposed development or drill through zones produced by the retired project wells)?

Should any of the answers be Yes, then a report must be submitted detailing why the permit(s), if approved, will not have a material impact on the credited reserves.

6.2. Land Reclamation Monitoring

The well site land reclamation process is to follow, at minimum, the plan submitted to the state regulatory body for returning the well operational area to its natural state, usually the oil and gas activity regulatory agency. Photographs documenting the wellsite in its entirety — from at least the four primary orthogonal directions prior to commencing plugging activity — shall be uploaded as part of project documentation, along with a satellite or drone overhead capture of the well site. The location and direction of the submitted photographic documentation of the wellsite shall be marked on the overhead site layout, so as to be replicated as part of annual monitoring report.

A copy of the land reclamation plan submitted to the regulator shall also be submitted to the platform along with the document ID. Any measurements or assessments required by the state regulator shall be uploaded as part of the annual monitoring report, as well as photographic documentation of the reclamation progress. The state regulator must sign off on reclamation completion after the designated state monitoring period.

6.3. Compensating for a Reversal

A reversal is defined as continuing or a renewal of extraction activity from the project reservoirs at any point, or continuing methane emissions in the vicinity of plugged wellbores. In the event of a detected or reported reversal, the extent will be quantified by an independent third party, according to best engineering practices, and a report will be submitted to the project ZeroSix platform page and stored on IPFS.

The report shall specify the amount of reserves that were released from the target project reservoir, how many more will be produced or released into the atmosphere in the future, and how the reversal will be addressed. A plan will be developed to permanently plug and abandon the infringing well and deduct any reversed credited volumes from the buffer account. If the violating well cannot be abandoned, the independent third party verifier must determine the volume of claimed project reserves expected to be produced economically from said producer or leaked from the improperly plugged well, and the corresponding number of credits shall be retired from the buffer account.

A benefit of oil and gas production reversal or leakage is that any such flow will occur slowly and consistently over time, limited by the productive capacity of the impeding well. Since the projects are to be low producing late life reservoirs with very low deliverability, this provides a large window of opportunity to resolve any identified reversal.

7. Verification

All the elements and provided information about the offsetting project are independently verified based on the source and nature of information.

7.1. Third-Party Verification of Project

An independent, state-accredited organization will verify the claimed emission volume abatement and credibility of the geologic permanence documentation of the project in a verifier report and certification statement submitted through the ZeroSix platform. At minimum, the specific engineers working within these organizations will hold a current state engineering license in a relevant engineering discipline.

The third-party verifier will review all submitted documents pertaining to geologic permanence, carbon content, and reserve volumes. Each relevant document will be verified independently through the ZeroSix platform. If the verifier has any questions or concerns about the quality of the claims or documentation they can revert back to the project owner to provide additional documentation or a revision of the project. Once all documents are consistent and meet the requirements laid out in this protocol the final certification can be issued.

7.2. Regulatory Compliance

Well-level critical project and regulatory sign offs from state regulatory bodies include:

- P&A permit filling and acceptance
- State-level confirmation of plugging and abandonment of economic reserves
- Land reclamation plan submission and approval as per regulatory requirements.

7.3. Monitoring

Monitoring of project area permitting and development activity is directly linked to state regulatory databases, hence verification is entirely linked with mandatory state fillings. Land reclamation monitoring and reporting is required by state regulators and, thus, such standards are enforced at the state level.

7.4. Execution

- P&A plan execution signed off by state observer and a copy of the document is uploaded to the ZeroSix platform
- Final land reclamation completion signoff is submitted at the time of final report

7.5. Data Quality

The quality of the verification is affirmed by the credibility of the submitted documentation from trusted public regulators. This includes the above mentioned state filings and permitting process, as well as the state agency confirmation of successful project execution according to submitted plans and in line with existing regulations. This process and documentation is already in use, is trusted, and doesn't require any additional modification.

7.6. Verification Processes and Entities

7.6.1. Trusted and Verified Information Source

The sources of the submitted documentation are verified and trusted industry third parties. This is the case with the reserve report and included volume determination, which is backed by state accreditation of the issuing engineer. The laboratory gas analysis results and oil API gravity from sales receipts are issued by third parties that have reputational or financial incentives to be accurate in their reporting.

7.6.2. Verification Process on Blockchain

The process of issuance and distribution of the calculated carbon credits to be issued for each project is governed by smart contracts that guarantee the trustworthiness of the ZeroSix platform. This process is transparent, open source, and immutable. The security of the underlying smart contracts and the platform itself have also been independently audited.

7.7. Double Counting

By registering an offset project, the project owner affirms that the eligible volumes have not been claimed for carbon offset credits on any other platform, for any other purposes for financial or other material compensation, or on the ZeroSix platform under a different project name.

Once a project has been successfully executed and the included wells have been P&A'd, their corresponding reserves no longer qualify as reserves, thus there is no risk of these volumes being claimed again for future carbon offsets — unless subsequent development of the project reservoir occurs in breach of the mineral rights limiting contract issued and tied to the mineral ownership title precluding the extraction of the relevant resources.

By tokenizing the ZeroSix credits on the blockchain, every credit can be verified through a public ledger, which holds all relevant information in a tamper-proof and immutable way, tracking the transaction history and means of generation for each metric ton of CO_2 equivalent credit. With full transparency, anyone can verify and check the credibility of the tokens, and any intentional or retiring or further transacting of already retired credits is prohibited.

8. Reporting

8.1. Initial Project Execution

The following list of documentation will be submitted to the digital solution and will be publicly available through the decentralized InterPlanetary File System (IPFS):

Table 4: Documentation requirements and issuing entity.

Document Title	Issuer
Oil Sales Receipt with API Gravity Test	3rd Party Oil Offtake Agent
Gas Analysis Report with Gas Heating Value and NGL Composition	3rd Party Gas Analysis Laboratory
Project Reserves Report - Field Monthly Forecast	Project Operator
Project Reserves Report - Well Level Volumes	Project Operator
List of All Well Penetrations Into/Through the Project Reservoir	Project Operator
Qualified Third Party Reserves Report	Licensed 3rd Party Engineering Firm
Third Party Reserves Report LOS and Financial Model Support document (xls)	Project Operator
Third Party Reserves Report Historical Production and Forecast Plots (pdf)	Project Operator
Mineral Ownership Schedule	Licensed Legal Entity
Working Interest Ownership Schedule	Licensed Legal Entity
Monitoring plan (as required by Regulations for wellbore emissions and land reclamation)	Project Operator
Permanence Report	Project Operator
P&A Plan and Regulator Permit Issuance	State Regulator
Land Reclamation Plan and Permit Issuance as Required by Regulator	State Regulator
Post-operations Report and Emissions Measurement as required by regulatory agency	Project Operator
Before and After Project Photographic or Video Documentation	Project Operator
Signatures	
Document Establishing a Legal Barrier to Future Extraction of Hydrocarbons	Licensed Legal Entity
P&A Operations Report and Regulatory Witness and Sign-off	State Regulator
Verifier Report and Certification Statement	Certified 3rd Party Verifier

The submission and verification of the necessary documentation, and successful execution of the digital signature will constitute all initial reporting requirements.

8.2. Annual Monitoring Reporting

The annual monitoring report is intended to verify the permanence of the project and the efficacy of proper abandonment and abatement of emissions from operations. The operator shall perform site specific measurements based on the nature of the historical operation and consequent environmental impacts and as required by the state regulator for land reclamation. This to include soil and water sampling from the vicinity of retired wellbores and reclamation progress as specified in the plan submitted to the state oil and gas industry authority in accordance with state reporting requirements. Any such required measurements and additional information is to be submitted annually.

8.3. Final Report

The final report must include the final measurements of air, soil, and water quality, where relevant, according to the standards of section 6.2 and consistent with the previous annual monitoring reports clearly validating the permanence of the retired reserves. Inclusive within the report will be results of land reclamation success authenticated by the state regulator. Also included can be documentation about realized co-benefits of the operation, which may be of interest to credit buyers or local stakeholders.

9. ZeroSix Credit Issuance and Crediting Period

9.1. Project Credit Ownership and Allocation

Oil and gas projects can involve complex royalty interests, thus the ownership of CO_2-equivalent credits associated with the project's emission avoidance must be clearly defined. The operating company has ownership of the credits and distributes the income–either in equivalent credits or in cash upon sale– based on the royalty interest. Alternatively, the credits can be distributed to the respective royalty owners at the point of crediting. All relevant interest owners would have to register on the ZeroSix platform as a prerequisite for this alternative to be actionable.

9.2. Buffer Account Allocation

Upon successful execution of the project, all associated carbon credits will be assigned (less the amount required for the buffer account) to offset any future unplanned reversals of retired hydrocarbon volumes. The percentage of credits withheld for the buffer account is aligned with the risk of reversals impacting the likelihood of permanence. The flat 1% withholding for the general reserve retirement project is a minimum amount arrived at upon evaluation of the risk matrix for these project types (see Section 2.9). The risks of reversal are low due to the stringent eligibility criteria and permanence requirements mandated by this protocol.

9.3. Project Credit Distribution

The full balance of carbon credit tokens will be generated and issued immediately upon the successful execution of the reserve retirement project according to the requirements governed by this protocol.

9.4. Project Credit Retirement

The issued project carbon credits will be able to be retired on the ZeroSix platform by either project owner, or any subsequent recipient of transferred credits. The retirement is executed by sending the number of credits equal to the desired amount of emission offsets to a terminal address. Subsequently a retirement certificate is issued on behalf of the claiming entity specified at the point of retirement.

10. Sustainable Development Goals (SDGs)

ZeroSix projects generate sustainable development improvements throughout the project life and beyond.

These co-benefits can include United Nations Sustainable Development Goals (SDGs) such as good health and wellbeing for the local community (SDG 3), clean water and sanitation (SDG 6), affordable and clean energy (SDG 7), responsible consumption and production (SDG 12), climate action (SDG 13), or life on land (SDG 15).[12]

Additionally, releasing the capital locked up in the most polluting operations will allow operators to transition toward cleaner energy sources more quickly through reinvestment of the revenue from gained credits into ventures such as carbon sequestration, renewable energy, or other carbon negative ventures.

The core initiative of this protocol is to accelerate society to a net-zero future, but many opportunities for co-benefits will be realized along the way.

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