BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF SCS CARBON TRANSPORT LLC FOR A PERMIT TO CONSTRUCT A CARBON DIOXIDE PIPELINE.	HP22-001

REBUTTAL TESTIMONY OF

ERIK SCHOVANEC

ON BEHALF OF

SCS CARBON TRANSPORT LLC

SCS EXHIBIT # ____

July 7, 2023

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Q. Please state your name and business address for the record.

A. Erik Schovanec. 2321 N Loop Drive, Suite 221, Ames, IA 50010.

Q. What is your position with SCS Carbon Transport, LLC ("SCS")?

A. As the Senior Director of Pipeline and Facilities for Summit Carbon Solutions ("Summit"), parent company of the Applicant SCS Carbon Transport LLC, I am responsible for the construction of Summit's Midwest Carbon Express pipelines and associated facilities, including those located in South Dakota. My duties encompass, but are not limited to, the pipeline routing; surveying (e.g., environmental, cultural, and civil); constructability reviews; contractor selection and management; material and equipment logistics; quality control and assurance; environmental best management practices and reclamation; schedule; and budget.

Q. Please briefly describe your education and experience.

A. I received my Bachelor of Science degree in Mechanical Engineering from Oklahoma State University. I have over 12 years of applicable pipeline design, construction, start-up, and operations experience for infrastructure projects in the midstream sector. I have served as a Project Engineer, Construction Manager, Engineering Manager, and Director of Engineering for large and small energy projects of varying product type across both the U.S. and Canada. I've directly overseen, or managed people overseeing, the installation of thousands of miles of pipe and dozens of pipeline facility installations. Prior to my current position as the Senior Director of Pipelines and Facilities for Summit Carbon Solutions, I worked for Blueknight Energy Partners, Hiland Partners, Kinder Morgan, and EPIC Midstream with primary responsibility for safe and reliable construction and operation of pipeline and pipeline facility assets.

Q. Have you previously submitted direct testimony and exhibits in this proceeding?

A. Yes.

Q. What is the basis for your rebuttal testimony?

A. I have reviewed direct testimonies of both Staff and Intervenor witnesses and would like the opportunity to address some of the comments, areas of concern, and questions.

Q. Have you reviewed the direct testimony of William Byrd, President of RCP Inc.?

A. Yes.

Q. Do you have any observations related to mainline valves as discussed in William Byrd's testimony?

A. Yes. In William Byrd's pre-filed testimony, page 9, lines 14-16, he states that he cannot pass judgment on the number of valves or their proper location. The Applicant will abide by all PHMSA requirements for valve locations and spacing requirements as dictated by 49 C.F.R. § 195.260. There are currently 56 mainline valves located in the state of South Dakota, of which 38 (68%) have executed voluntary easements. As valve locating is an iterative process, final site locations cannot be provided at this time. The Applicant continues to work with landowners to find appropriate locations that meet or exceed the requirements of 49 C.F.R. § 195.260 while minimizing the impact to landowners.

Q. Mr. Byrd's testimony indicates that he has not seen details concerning SCS' plans to address internal corrosion. Bill Caram of the Pipeline Safety Trust and Curtis Jundt also express concern with impurities in the CO2 that will speed up corrosion. Does SCS have a plan to avoid internal corrosion? Please explain.

A. Yes. There are a number of ways that SCS is addressing internal corrosion. The most important factor defining the potential corrosivity of supercritical CO2 is the possibility of a separate water phase condensing out of the CO2 stream resulting in a free water phase. To mitigate this, the Applicant will be installing a triethylene glycol skid at every capture facility to dehydrate the CO_2 stream. The Applicant will also be installing a moisture analyzer to ensure the CO_2 stream meets system specification before it enters the pipeline. If the CO_2 stream does not meet system specification, an alarm would immediately notify the Control Room which would trigger the shutdown of the capture facility, effectively isolating the capture facility and preventing elevated water content CO_2 from entering the pipeline.

On top of these active measures, the Applicant will also install corrosion monitors at every capture facility. As noted by Mr. Byrd, SCS will also be installing pig launchers and receivers which will be used to facilitate launching of maintenance pigs (as required) as well as to conduct periodic in-line assessments with smart tools to monitor potential corrosion.

Q. Mr. Byrd and Darren Kearney, SD PUC Staff Analyst, recommend the installation of pipeline warning tape. What is SCS's current position on installation of pipeline warning tape?

A. SCS is still of the belief that current regulations and best practices such as compliance with the 811 "One Call" system, location of pipeline markers, providing landowners with as-built certified plats depicting the pipeline location, routine aerial surveillance, etc. are sufficient to protect a pipeline system, as seen by the track record of safety for PHMSA pipelines.

The depth of the warning tape would also present a challenge as the tape would need to be a sufficient distance above the pipe so that it can be identified before the pipe is impacted during excavation activities, but it also needs to be deep enough to not be disturbed during normal farming operations.

With that said, if asked to do so, SCS would be willing to install warning tape, as it is a relatively low-cost item that can be done to add another potential layer of safety to our system.

Q. Mr. Byrd and Mr. Kearney recommend the installation of a fiber optic leak detection system. Has SCS considered installation of a fiber optic leak detection system, and what led to SCS's conclusion that the benefits were significantly outweighed by the downside?

A. For perspective, a very, very small percentage of pipelines in the US have fiber installed for leak detection; I am not aware of any fiber systems installed on the 2600+ miles of PHMSA pipelines in South Dakota. However, I do have a significant amount of experience installing and operating a distributed acoustic sensing (DAS) fiber optic leak detection on pipelines. As a management group, SCS staff have overseen the installation and operation of nearly 2,000 miles of hazardous liquid pipelines that were installed with fiber optic cable. With my direct experience, I am qualified to speak to the benefits and the shortfalls of a fiber optic leak detection system. In short, in nearly 4 years of operation, the fiber optic system that I had experience with did not perform as expected, caused countless landowner issues with digging and trenching taking place for years after the initial ROW reclamation to conduct periodic maintenance and repair to the leak detection system (not the pipeline), and cost well over $100 million to install.

Post-Construction Soil and Crop Disturbance: Installing a DAS fiber system will involve excavation and soil disturbance, disrupting farmland post reclamation after the pipeline is installed and operational.

This is due to several reasons including that the conduit housing the fiber and handholes (underground vaults that provide access for the fiber to be pulled, spliced or repaired) are installed with the pipeline; the fiber is not pulled into the conduit through the handholes (located in farmers' fields) until after the pipeline is installed and generally after conventional pipeline construction cleanup is complete. Doing so caused anger and frustration to landowners to see heavy equipment and personnel back out on the right-of-way tearing up their farmland again after it was restored.

Once the fiber is pulled in and the system is commissioned, we experienced dozens if not hundreds of locations (based on the length of our pipeline system) where the integrity of the fiber or conduit was compromised, requiring contractors to again access the landowners property to traverse farmland and crops to access points of excavation and conduct excavation activities. This will potentially be a third time that SCS would need to disrupt farming operations, damaging the farmer's crops and to conduct restoration activities. Keep in mind that the 2nd and 3rd time that the farmer's fields are accessed (after pipeline construction is complete), that the topsoil will not be stripped off of the ROW, which will result in mixing of the topsoil and subsoil which may significantly harm crop yields.

Maintenance Challenges: Maintaining a DAS fiber leak detection system on a pipeline across farmland poses unique challenges. In addition to startup and maintenance issues described above, resulting in accessing properties repeatedly, there are other challenges. False alarms occur which result in unneeded shutdowns creating transient conditions with frequent system shutdowns and startups. Frequent starts and stops affect steady state operations which potentially adversely affects Summit's ability to detect and respond to system abnormalities. The system relies on continuous monitoring and data analysis to detect leaks or faults along the pipeline. However, in a farm setting, the system may face frequent disruptions due to the activities and operations carried out on the land. Farming activities, such as plowing, tilling, or even livestock grazing, can inadvertently damage or interfere with the fiber cables or handholes, leading to false alarms or unreliable detection system abnormalities. These false positives can result in reduced effectiveness of not only the fiber optic leak detection system, but also the RTTM leak detection system we have proposed.

Easements: SCS assumes that all easements that have been executed to date would need to be renegotiated to allow for the installation of fiber in the ditch with the pipeline. This would not only cost a huge amount of time and energy, but it would also place a substantial burden on landowners by having to engage in discussions a second time.

Cost and Economic Considerations: Implementing a DAS fiber leak detection system on a pipeline is very expensive. The installation and maintenance costs, when purchasing fiber optic cables, specialized equipment, and skilled labor can be substantial. My experience installing ~2,000 miles of fiber leak detection systems included spending approximately $50-60K per mile to install the fiber leak detection system, or the equivalent of $24 to $29 million for our proposed CO2 system in South Dakota. Keep in mind that those systems were installed in west Texas where the weather and construction was more conducive for installation, and it was not installed in prime farmland. I imagine the installation cost in South Dakota would be higher. It is hard to quantify but based on the point above regarding renegotiation of easements, we anticipate that we would need to pay tens of millions to renegotiate executed easements (over 900 tracts to date in South Dakota). We estimate the total cost impact for installing fiber to be roughly $50 million.

Additionally, the potential disruptions to farming activities and crop damages mentioned earlier can lead to financial losses for farmers which translates to additional expense for SCS. We also anticipate ongoing incremental operational cost of $1 million+ per year to operate the fiber system.

SCS' Planned Leak Detection System: The system that SCS currently plans to install, Atmos Pipe, meets API Recommended Practice 1175 – Pipeline Leak Detection – Program Management. Each leak detection system's performance (including the one SCS will install) must be tested before acceptance for deployment. The performance is based on learning the system via training on a wide range of potential operating conditions. Alarm tuning needs a baseline and uses real time flows and temperatures and is impossible to test without a phase one pipeline build. Atmos is one of the most experienced leak detection vendors in the world. They have installed more than 1,700 systems in 65 countries with over 900 in North America.

Summit's multi-layer leak mitigation/detection system approach employs:

- Atmos Pipe CPM;
- Custody transfer quality metering at all receipt and delivery sites;
- Twelve over/short segments, thus increasing the sensitivity of the system to more quickly determining a loss of containment site;
- Space based geohazard analysis for determining landscape changes after significant weather events;
- "Rate of Change," automatic valve closure capability (Both valve site pressure transmitters capable of closing a valve at a programmed low-pressure set point automatically);
- A line pack calculation that maintains a system inventory balance calculating the receipts and deliveries displaying the loss or gain of CO_2 in the pipeline;
- Pipeline training simulator built using the SCS system diagram with site elevations. This world class tool will safely expose our pipeline controllers to dozens of leak scenarios before the system becomes operational.

It is my considered judgment that a fiber optic leak detection is too costly to install and maintain and introduces unnecessary risk to more reliable leak detection systems such as the Atmos system that SCS plans to install and operate.

Q. Mr. Byrd and Mr. Kearney recommend that direct forms of CO2 detection be installed at pump stations. What is SCS's plan for CO2 detection at pump stations?

A. The Applicant will be utilizing a variety of direct detection methods at pump stations including CO2 detectors as well as thermal cameras that would capture the heat signature of CO2 changing phases from supercritical to gas.

Q. Mr. Byrd and Mr. Kearney recommend that SCS use API 1169 certified construction inspectors to oversee construction in South Dakota. Does SCS agree with this recommendation?

A. No. This requirement does not align with typical industry practices nor is it applicable to all inspectors. API 1169 does indicate a general understanding of pipeline construction and some inspectors on the project will already have the 1169 certification. However, the Applicant does not believe it to be a valid indicator of each inspector's experience and will look at the candidate as a whole rather than a singular certification. In addition, many inspectors will have specialized training and certifications, covering tasks like welding, coating, and non-destructive examination, which requires an understanding of the specific construction activities beyond the elementary understanding required by API 1169. The Applicant acknowledges that the API 1169 certification would be a benefit to some roles but not all. Further, the Applicant must meet the PHMSA requirements under 195.204 Inspection – General, which states: "Any operator personnel used to perform the inspection must be trained and qualified in the phase of construction to be inspected." It should also be noted that, in addition to not being a PHMSA requirement, a majority of major pipeline operators do not require this certification for their pipeline inspectors.

Q. Mr. Byrd and Mr. Kearney recommend the Commission require SCS implement API Recommended Practice 1172: *Recommended Practice for Construction Parallel to Existing Underground Transmission Pipelines*. Does SCS agree with this recommendation?

A. No. While API Recommended Practice 1172 details industry best practices that will already be executed by the Applicant, it is at best, a recommendation and should not be used as a ”one-size fits all”. The Applicant is already in discussions with many of the third-party utility companies that will be crossed and will coordinate all utility crossings in good faith. This, paired with the one-call system, will ensure third parties are comfortable with the construction practices around their assets. Requiring API Recommended Practice 1172 would create an onerous process for not just the Applicant, but all third parties that are impacted as any waivers to the recommendations would be required to be in a written agreement.

Q. Do you have any other observations concerning Mr. Byrd's testimony?

A. No.

Q. Have you had the chance to review the testimony of Darren Kearney, Staff Analyst at the SD PUC?

A. Yes.

Q. Did you review Mr. Kearney's testimony regarding an indemnity bond for road and bridge damage according to SDCL § 49-41B-38?

A. Yes. I reviewed Mr. Kearney's proposal and find it acceptable. SCS agrees with his methodology for determining the amount of $23 million (2.9% of total project cost in South Dakota).

Q. Mr. Kearney and Staff recommend that the Commission require a third-party environmental inspector during project construction and reclamation. Does SCS agree with this recommendation?

A. Yes. SCS also sees the benefit of having this resource on the project and will commit to utilizing a third-party environmental inspector as recommended by the SD PUC Staff.

Q. Mr. Kearney and Staff recommend that the Commission require a public liaison officer for the Project. Does SCS agree with this recommendation?

A. Yes. SCS also sees the benefit of having this resource on the project and will commit to utilizing a public liaison officer as recommended by the SD PUC Staff.

Q. Do you have any other observations concerning Mr. Kearney's testimony?

A. No.

Q. Have you had the chance to review the testimony of Sara Throndson, Associate Partner at Environmental Resources Management?

A. Yes.

Q. Ms. Throndson advises that a Geohazard Analysis be completed by SCS. Can you address those concerns?

A. Yes. The Applicant commissioned a Phase I Geohazard Assessment with an initial draft issued on May 19, 2023, and a revised draft issued on June 9, 2023. Upon further analysis, and as detailed in the Phase I Geohazard Assessment, the karst hazard rating on SDT-209 as called out in Section 5.1.5 Table 8 has been revised from "high" to "low". These results are also corroborated by Jaron Condley's testimony of the South Dakota Geological Survey, "there is no known karst topography along the proposed pipeline route". Additionally, the landslide risk rating for SDL-320 as called out in Section 5.1.5 Table 8 has been revised from "Moderate

Susceptibility & Low Incidence" to "Low Incidence". The Applicant can supply the Phase I Geohazard Analysis in draft form.

Q. Do you have any other obversations concerning Ms. Throndson's testimony?

A. No.

Q. Have you had the chance to review the testimony of Gary Napp from Environmental Resources Management?

A. Yes.

Q. Do you have any comments related to the additional air quality mitigation measures recommended by Mr. Napp?

A. As suggested by Mr. Napp, SCS was already planning to use low-emitting equipment for the majority of all major construction equipment, and all equipment will be properly maintained. SCS will also commit, when possible, to using tarps or dust covers when transporting materials with significant dust content. Lastly, SCS will minimize idling of construction equipment and diesel-powered vehicles to reduce exhaust emissions.

Q. Do you have any other observations concerning Mr. Napp's testimony?

A. No.

Q. Have you had the chance to review the testimony of Janet Holmes from Ag Advisory and landowners?

A. Yes.

Q. Ms. Holmes and many of the landowners are concerned about the restoration of their property. What restoration efforts does SCS plan to utilize on landowners' properties?

A. In addition to the Environmental Construction Plan (ECP) which has been submitted, SCS has committed to producing an Agricultural Impact Mitigation Plan (AIMP) which will be submitted to the SD PUC prior to the hearing. The AIMP will provide more detail on how the restoration activities will be conducted, but a brief overview is listed below.

During grading activities, the topsoil will be stripped and stockpiled on the edge of the right-of-way (ROW). When the ditch is cut, the subsoil will be placed on the other side of the ROW, which will prevent mixing of the subsoil and topsoil. Both piles will be stabilized, as required.

Agricultural and pastureland compacted by heavy project equipment, including off ROW access roads, will be deep tilled to alleviate soil compaction upon completion of construction on the property. Tillage will precede replacement of topsoil.

Rutted land will be graded and tilled until restored as near as practical to its preconstruction condition. Rutting will be remedied before topsoil is replaced. Excess rocks larger than three inches in average diameter will be picked and removed from the right-of-way. The slope, contour, grade, and drainage pattern of the disturbed area will be restored as nearly as possible to its preconstruction condition. However, the trench may be crowned to allow for anticipated settlement of the backfill. SCS will remediate areas of excessive or insufficient settlement in the trench area which visibly affects land contour or undesirably alters surface drainage. Disturbed areas where erosion causes excessive rills or channels or areas of heavy sediment deposition, will be regraded as needed. On steep slopes, methods such as sediment barriers, slope breakers, or mulching will be used as necessary to control erosion until vegetation can be reestablished.

Additionally, SCS will perform post-construction monitoring and inspection to ensure restoration is sufficient. SCS will warranty construction work and will address post-construction deficiencies that are identified either from landowner contact, through aerial patrols, or ROW inspections.

Q. Landowners testify that they will be unable to use equipment with tires four feet in diameter or larger because the tires could come into contact with the pipeline. Does SCS have any limitation on how large equipment would be operated above the pipeline?

A. No. SCS has not placed any restriction on landowners on the size of tires or weight of equipment that they can operate over the pipeline. Further, if a landowner has practical concerns with farming operations, both normal and abnormal, which will impact 4+ feet below the surface, SCS can agree, and has agreed on hundreds of tracts, to bury the pipeline deeper at the landowner's request to eliminate those concerns. Compaction that occurs due to normal pipeline construction greatly reduces the risk associated with equipment crossing the permanent ROW and existing pipeline installations in South Dakota are proof that instances of equipment sinking are extremely rare.

It should be noted that by going 4' deep, SCS is already exceeding PHMSA design requirements for depth of cover, as 36" or less of cover is required in all areas outside of crossing large inland bodies of water and deepwater port safety zones. It should also be noted that SCS has performed an analysis for both static and live loads assuming worse-case scenarios for agricultural and nonagricultural equipment.

Q. Do you have any other observations concerning Ms. Holmes' or landowner's testimonies?

A. No.

Q. Have you had the chance to review the testimony of Brian Sterner at Environmental Resources Management?

A. Yes.

Q. Mr. Sterner is concerned Summit will only use One Call resources to identify utility lines. Does Summit plan on using other approaches to identify underground private utility lines that would not normally be addressed by a One Call service?

A. There are a variety of methods to identify and locate underground utilities outside of the One Call system. Locating of third-party utilities starts with a variety of publicly available databases to locate pipelines, waterlines, drain tile, communication lines, and powerlines. Field surveys are also conducted where crews look for signs of buried utilities which may include roadside markers and clear right-of-way. In addition, the Applicant receives feedback from Landowners, Counties, and title research to identify additional third-party utilities. Once a foreign utility operator is identified, the Applicant will notify the foreign utility operator of the crossing and work collaboratively to identify any additional crossings that may exist.

Q. Do you have any other observations concerning Mr. Sterner's testimony?

A. No.

Q. Have you had the chance to review the testimony of Chris Jundt?

A. Yes.

Q. Mr. Jundt claims it could take up to 30 minutes before an upstream valve is shut after a leak. Do you agree with this assertion? What technology allows SCS to ensure a shutdown will happen in minutes?

A. No. I don't agree with Mr. Jundt's assertion that it would take 30 minutes for a valve to close in the event of a leak.

First, I'd like to provide more detail on what will be present at each of our mainline valve settings, how each valve is controlled, and the valve closure times. All mainline valves will be electrically actuated, have upstream and downstream pressure transmitters, redundant communications, and a local PLC. The SCS pipeline will be controlled using our control center SCADA system which will operate 24/7, 365 days a year. The valve closure times range from ~15 seconds for 6" valves and up to ~120 seconds for the 24" valves.

During the commissioning process, all remote devices on the system will be point to point checked from the end device to the SCADA screen. All associated alarm and shutdown set points are confirmed and documented with the control room. The SCADA system polls data (such as pressures from the pressure transmitters) at intervals from 3 to 9 seconds. The transmitters will have rate of change alarms as well as low or high pressure alarms. In the event of a leak (and associated pressure drop), an alarm will be sent to the pipeline controller which will notify the controller of an upset condition, or in the event of a large pressure drop, will trigger the mainline valve to shut automatically. The command would be sent in a matter of seconds, and then valves would shut according to their closure times. Mainline valves are tested twice a year to ensure functionality.

Q. Mr. Jundt expresses concern with water hammer and an upstream valve closing too quickly causing the pipeline to overpressure. What has SCS done to mitigate those concerns?

A. SCS completed a comprehensive surge analysis on the entire system to ensure compliance with the PHMSA regulations, specifically CFR 195.406(b), which requires system pressures to not exceed 110% of the system's maximum operating pressure (MOP) during transient or other abnormal activities. SCS took a conservative approach during this analysis in

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that only local system controls were considered for system protection. In reality, the control center operators will be an extra layer of protection in any upset condition.

The surge analysis was conducted using actual proposed operating conditions and design - flow rates, pipe sizes, elevation changes, pump and compressor curves, product composition, valve closure times, and a variety of other factors. The analysis determined that our pipeline system was adequately protected from overpressure in all inadvertent valve closure scenarios meaning that the system cannot be overpressured by a mainline valve shutting either normally or abnormally. Even though we did not find a risk of overpressure with the indicated report, we are implementing surge mitigating automation such as automatic pump station shut down with downstream valve closure. This analysis will be updated and expanded as the pipeline system grows or additional volume is added.

Q. Do you have any other observations concerning Mr. Jundt's testimony?

A. No. I would note that Mr. Jundt has concerns about corrosion which have been addressed earlier in my testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Dated this 7th day of July 2023.

/s/ Erik Schovanec

Erik Schovanec