Small-Scale High Voltage Direct Current

A Lessons Learned Review of the Polarconsult HVDC Phase II Project with Recommendations for Future Research and Alaskan Application

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Executive Summary

The Polarconsult Small-Scale High Voltage Direct Current (HVDC) project seeks to design, develop, and demonstrate 1) small-scale HVDC converters and 2) innovative complementary transmission infrastructure with the goal of reducing costs for applications in rural Alaska. The project is funded by the Denali Commission, and is comprised of three phases. This report provides a summary review of Phase II project activities, and focuses on lessons learned and recommendations for appropriate next steps in terms of technology research and application in Alaska. In addition, pertinent context, concepts, and background information are discussed to inform this review.

Lowering the cost of power transmission via HVDC has been suggested as an option to reduce and stabilize the cost of delivering power to Alaska's rural villages. Power in most of the villages is provided by diesel powerhouses. The high and volatile price of diesel often means significant economic hardships for those communities. Transmission by Alternating Current (AC) is limited by high costs, and line losses that increase with transmission distance. Direct Current (DC) transmission, in contrast, has fewer infrastructure requirements and lower line losses, and can be economical over long distances. Because AC power has been the dominant worldwide standard for generation and transmission, the use of DC for power transmission requires conversion from and to AC in order to integrate it into the existing AC infrastructure. Large-scale HVDC systems, on the order of 100s to 1000s of MWs and designed to wheel large amounts of power across long distances, have been in use since the mid-20th century. However, the electrical demand of rural villages in Alaska is much smaller, typically less than 1 MW. At this scale, existing HVDC technology is not available. Therefore, the development of small-scale HVDC systems, power converters, and multi-terminal networks, are of critical need if HVDC technology is to be applied in rural Alaska.

Our life-cycle cost analysis indicates that 60 miles is about the intertie length at which HVDC becomes an economically attractive option, although the cost estimation has some scatter because the economic analyses in this report are based on assumed data from different sources. Both high and low end cost estimates are given in this report. More empirical data for small-scale HVDC intertie are needed for a more rigorous economic analysis.

Phase I of this project sought to evaluate the technical feasibility of small-scale HVDC converter technology through evaluating the design, modeling, prototyping, and testing of a bench-scale converter. In addition, Polarconsult sought to evaluate the technical and economic feasibility of the overall system and estimate the potential savings compared to an AC intertie. In this phase, a prototype 250 kW 12.5 kV HVDC converter was successfully laboratory-tested, which confirmed that the technology met key performance benchmarks. Phase I was completed in 2009.

Phase II of the Polarconsult HVDC project included design, fabrication, and testing of fully functional prototypes of the converter and transmission system elements. This effort sought to validate the design and functionality of these systems, and the efficiency and feasibility necessary to make HVDC systems successful in remote Alaska intertie applications. Phase II was completed in May 2012.

Phase III is an additional concept phase that seeks to fix existing problems with the converter and then field-demonstrate the converter technology developed and refined through Phases I and II. Polarconsult is currently seeking funding to execute this phase.

During Phase II, a 1 MVA converter for a 50 kV DC transmission system, consisting of two 500 kVA modules, was designed, constructed, and tested. While the project demonstrated the technical feasibility of the converter, several critical hardware issues arose during testing that need to be addressed before further demonstration can occur. Once a fully functional prototype is developed, independent testing of the converters will still be needed to validate efficiency and performance.

Next, the prototype will need to be deployed on an Alaskan utility system to validate its functionality and reliability in a commercial setting. The field test will also provide an opportunity to observe and meet the nontechnical

challenges that exist to deployment in Alaska. Aside from technical problems, there are problems due to the lack of labor and appropriate human capital in remote Alaskan regions to maintain, operate, and repair equipment.

From this demonstration, it is recommended that before further project activities commence, design and performance standards for the envisioned converter technology be formally codified by professional stakeholders. Such standards could include target operating conditions, operations and maintenance requirements, integration and controls functionality, and even materials characterization. It is further recommended that future project funding for converter development be conducted under a competitive solicitation, such as a Request for Proposal (RFP) process using the developed standards as product specification.

Also during this next phase, Polarconsult conducted a field demonstration of a system composed of a glass fiber-reinforced polymer (GFRP) pole, micro-thermopile pole foundations, micro-thermopile guy anchors, and screw guy anchors. This demonstration successfully displayed a potentially viable alternative approach to developing transmission in Alaska by designing "up" based on location rather than just modifying current industry practice. However, there was concerns identified with the demonstration that limit the ability to assess the demonstrated system, and make recommendations regarding the design, performance, and functionality.

From this demonstration, it is recommended that further development of an Alaska-specific design approach to transmission be conducted as a separate activity from the development of small-scale HVDC converters. Significant work remains in terms of developing and demonstrating this approach as a technology that is commercially ready and without significant risks for an Alaskan utility or operator. It is further recommended that before further development takes place, both an interested party (e.g. an Alaska utility, operator, or key stakeholder) and a specific application (separate from small-scale HVDC transmission) be identified.

As a component of developing and demonstrating transmission infrastructure for this phase, single-wire earth return (SWER) was proposed for Alaskan applications by Polarconsult. While HVDC alone can potentially reduce electricity costs in rural Alaska, HVDC in conjunction with SWER has the potential to enable even greater cost reductions than HVDC can achieve alone. SWER remains an intriguing possibility for particular transmission projects in Alaska, whether AC or DC, given Alaskan conditions such a low-density, widely scattered population, and very little infrastructure in areas in between population centers. Two SWER projects in Alaska have demonstrated SWER as a technically feasible, low-cost method of transmission. However, they also highlighted serious questions concerning conductance in frozen soils, fault and safety strategies, reliability, system longevity, and pole design and construction. In addition, state regulations significantly limit the use of SWER. It is recommended that future investigation should be conducted as a separate activity and only with significant "buy-in" from key stakeholders.

The economic analysis completed as part of this report suggests that HVDC with SWER may be economical under conditions that are very reasonable to assume. Among these conditions are low population density, and rising cost of diesel. Another is a decrease in capital costs as small-scale HVDC products achieve substantial production volume. The economic findings of this report are limited, however, given the number of assumptions made for a pre-commercial technology and the unknown costs associated with the significant hurdles to overcome in terms of commercialization. Cost estimates for the converters and transmission system components have been refined from Phase I findings, but still incorporate significant uncertainty.

Finally, the technology used to develop the converters under this project allows for the potential application of multi-terminal networks. Multi-terminal networks are of particular interest to this project given the regional scattering of isolated Alaskan villages; a multi-terminal network could theoretically interconnect a series of villages, thus decreasing operational costs and increasing efficiency by concentrating power service in one location. Alternatively, a distant renewable resource, such as hydroelectricity, could be connected via a multi-nodal or multi-terminal network to several communities within a region. However, multi-terminal networks have had limited global field testing and application. It is recommended that this technology be monitored as it is deployed and refined over the next few years, and that lessons learned are captured and integrated into future Alaska small-scale HVDC considerations.

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List of Terms

Alaska Center for Energy and Power (ACEP)	An applied energy research group housed under the Institute of Northern Engineering at the University of Alaska, Fairbanks. ACEP is the program manager for the Emerging Energy Technology Grant (EETG) on behalf of the Denali Commission, and the grant manager for Phase II of project activities.
Alaska Department of Labor (AKDoL)	The government entity responsible for enforcing the National Electric Safety Code (NESC) in Alaska.
Alaska Village Electric Cooperative (AVEC)	A cooperatively-owned electrical utility that provides power to 54 villages in the interior and western Alaska. AVEC was the grant manager for Phase I of project activities, and a key stakeholder for technology development.
Alternating Current (AC)	A power delivery method in which the current periodically reverses direction; most commonly used power delivery and distribution method today.
Asynchronous power	An instance in which two power grids are not on the same power standard, for example, one is AC and the other is DC, or both are AC at different frequencies or phases
Black start	The process of restoring power to a transmission system after a total or partial shutdown, without relying on the external network.
Capacitance	The ability of an object to maintain electrical charge.
Current Source Converter (CSC)	An inverter whose commutation is controlled by the power circuit.
Denali Commission	Introduced by Congress in 1998, the Denali Commission is an independent federal agency designed to provide critical utilities, infrastructure, and economic support throughout Alaska. The Denali Commission is the primary funder of the Polarconsult Small-Scale HVDC Project.
Direct Current (DC)	A power delivery method in which the current maintains constant direction.
Electric Power Research Institute (EPRI)	A nonprofit organization which conducts research on issues related to the electric power industry (electric power generation, delivery and its use).
Emerging Energy Technology Fund (EETF)	An ongoing State of Alaska program, co-funded by the Denali Commission and administered by the Alaska Energy Authority, intended to fund emerging energy technologies for demonstration in Alaska.
Emerging Energy Technology Grant (EETG)	A 2009 Denali Commission program designed to fund emerging energy technologies for demonstration in Alaska. This project is included under the EETG program due to similar goals and objectives, although not funded through the program.
Federal Energy Regulatory Commission (FERC)	The United States federal agency that oversees interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates.
Glass-Fiber-Reinforced Polymer	Material used for Polarconsult conceptual transmission pole, demonstrated during this project.

(GFRP)	
High Voltage Direct Current (HVDC)	A power delivery method that uses direct current and high voltages (generally on the order of 100s of kilovolts).
Impedance	A measure of the opposition to current that a circuit presents when a voltage is applied.
Inductance	A measure of the amount of voltage induced across a conductor in the presence of a changing current.
Institute of Social and Economic Research (ISER)	University of Alaska Anchorage center devoted to studying economic and social conditions in Alaska. ACEP and ISER share a joint position, which was responsible for conducting the economic analysis included in this report.
Institute of Electrical and Electronics Engineers (IEEE)	The professional association for electrical engineers, which established the National Electrical Safety Code in the United States.
Insulated Gate Bipolar Transistor (IGBT)	A type of three-terminal, semiconductor-based electronic switching device.
Inverter	An electrical power converter that converts DC to AC.
Kilovolt (kV)	One thousand volts.
Line-Commutated Converter (LCC)	An inverter whose commutation is controlled by the power circuit.
Multi-nodal	Synonymous with "Multi-terminal."
Multi-terminal	A network with more than one terminal (node).
National Electrical Safety Code (NESC)	The United States standard for electrical safety.
Polarconsult Alaska, LLC (Polarconsult)	A private engineering firm based in Anchorage, Alaska, and project lead.
Princeton Power Systems (PPS)	PPS is a manufacturer of advanced power conversion products and alternative energy systems, and developed the small-scale HVDC converters discussed in this report.
Pulse Width Modulation (PWM)	A technique for controlling power to electrical devices.
Railbelt	A term referring to the broad geographic area served by the Alaska Railroad from the Kenai Peninsula to Fairbanks, which is also connected by the State's largest electricity grid.
Reactive Power	The energy stored in an inductor or capacitor on an AC circuit, resulting from the phase lag between voltage and current that the inductor/capacitor introduces by storing and then releasing power in each current cycle.
Real Power	The net amount of power transmitted by a transmission line.
Rectifier	An electrical power converter that converts AC to DC.

Rural Utilities Service (RUS)	An agency of the United States Department of Agriculture (USDA) charged with providing public utilities (electricity, telephone, water, sewer, etc.) to rural areas in the United States via public-private partnerships.
Shield wire	An electrical cable in which the conductor or conductors are enclosed in a conductive layer.
Single-Wire Earth Return (SWER)	A system by which the earth is used as the return portion of a circuit.
Single-Wire Ground Return (SWGR)	Synonymous with "SWER."
Single-phase power	A system of AC power delivery in which all components are at the same phase at the same time.
Stakeholder Advisory Group (SAG)	The SAG was a professional advisory council designed to provide independent comments, feedback, review, and recommendations to the project. The SAG was chaired by the Denali Commission, and consisted of 30 members. The SAG met formally 3 times over the course of the project to discuss project issues and provide formal feedback to the project.
Synchronous power	An instance in which two power grids are at the same phase at the same time.
Three-phase power	A system of AC power delivery in which three different conductors are used, each out of phase with the other two by 120 degrees.
Thyristor	A solid-state semiconductor device used as switches for handling large amounts of power.
Triplen harmonics	Odd multiples of the third harmonic (e.g., 3rd, 9th, 15th…). Harmonics are steady-state distortions of the fundamental frequency of the AC; triplens are of concern because they are additive in the neutral and can lead to dangerously large currents.
Two-phase power	A system of AC power delivery in which two different conductors are used, the second out of phase with the first by 90 degrees.
Voltage Source Converter (VSC)	An inverter whose commutation is controlled by its own control system, instead of by the power circuit.

1.0 Introduction

The Polarconsult Small-Scale High Voltage Direct Current (HVDC) project seeks to design, develop, and demonstrate 1) small-scale HVDC converters and 2) innovative complimentary transmission infrastructure with the goal of reducing costs for rural Alaskan application. The Denali Commission with the Alaska Village Electric Cooperative (AVEC) previously funded Phase I of this project. Phase I included a feasibility analysis of the proposed HVDC system and construction and testing of a prototype 250 kW 12.5 kV HVDC converter to confirm that the technology met key performance benchmarks. Phase I was completed in 2009 [1].

Phase II of the Polarconsult HVDC project included design, fabrication, and testing of laboratory-functional prototypes of the converter and transmission system elements. This effort sought to validate the design and functionality of these systems, and evaluate the efficiency and feasibility necessary to make HVDC systems successful in remote Alaska intertie applications. Phase II was completed in May 2012 [2].

There is an additional concept phase to the Polarconsult HVDC project, Phase III, that seeks to demonstrate the converter technology developed and refined through Phases I and II in the field. Polarconsult is currently seeking funding to execute this phase.

This report provides a summary review of Phase II project activities, focusing on lessons learned and recommendations for next steps in terms of technology research and application for Alaska. In addition, pertinent context, concepts, and background information are discussed to inform this review. The remainder of this report is organized into the following sections:

- Section 2: Project Context
    - Context for this Alaska-specific project, including general information on the perceived need, application, and summary information on project activities.
- Section 3: Technology Background Information
    - Pertinent background information for a basic technical understanding of both the project and of this review. Topics include historical perspective of HVDC, HVDC scales and application, multi-terminal networks, and single-wire earth return (SWER) transmission.
- Section 4: Project Review: Small-Scale HVDC Converter Development and Testing
    - A review of the primary project activity—development and testing of the small-scale HVDC converter.
- Section 5: Project Review: Feasibility of HVDC Transmission
    - A review of the secondary project activity—the investigation of the feasibility of construction methods necessary to make HVDC systems a success in rural Alaska applications.
    - This section includes a review of the following:
        - Economics of Transmission of RUS Design Approach
        - Demonstration of Alaska-specific Design Approach
        - The Feasibility of SWER in Alaska
- Section 6: Summary of Findings and Recommendations
    - A summary of lessons learned from the project and recommended next steps concerning technology research, development, and application

2.0 Project Context

HVDC has been suggested as an option to reduce and stabilize the cost of power delivery in Alaska's rural villages. Power in most villages is provided by diesel powerhouses. The high and volatile price of diesel often means significant economic hardships for communities which rely on diesel for power generation.

Transmission by Alternating Current (AC) is limited by high costs, and line losses that increase with transmission distance. Direct Current (DC) power transmission, in contrast, has fewer infrastructure requirements and lower line losses, and can be economical over long distances. Because AC power has been the dominant worldwide standard for generation and transmission, use of DC for power transmission requires conversion from and to AC to integrate it into the existing AC infrastructure.

Large-scale HVDC systems, on the order of 1000s of MWs and designed to wheel large amounts of power across long distances, have been in use since the middle of the 20th century. However, the electrical demand of rural Alaskan villages is much smaller, typically less than 1 MW, and existing HVDC technology is not economical at this scale. Therefore, the development of small-scale HVDC systems and power converters, plus multi-terminal networks, is a critical need if HVDC technology is to be applied in rural Alaska.

An HVDC power transmission system in a rural Alaskan application could help lower the cost of power through any of three scenarios. One scenario is that it could deliver reliable and relatively inexpensive power from either the Railbelt or communities that already have an inexpensive and reliable power source. A second scenario is that it could link villages together so they could share local power sources and expenses, enabling them to develop resources that are feasible only with their economic power combined. A third scenario is that it could enable rural villages to connect to and access stranded energy sources, such as wind and geothermal power.

2.1 Polarconsult HVDC Project Overview

Polarconsult, a private engineering firm based in Anchorage, Alaska, has advocated for the concept of small-scale HVDC as an option for rural Alaskan transmission systems for many years. Specifically, they identified technology gaps and possible applications for the development of small-scale HVDC in Alaska. To address this technology hurdle related to manufacture of small-scale, affordable converters, Polarconsult actively surveyed vendors of related power electronic equipment to seek an interested developer. This resulted in identifying Princeton Power Systems (PPS) as a technically capable and interested vendor. Polarconsult circulated a "white paper" informational publication on their concept among key Alaska stakeholders in 2005. This eventually identified AVEC as an interested utility partner. AVEC long considered the economic and operational advantages of electrically connecting the rural communities they serve, but were often stymied by per-mile transmission costs using traditional AC. Small-scale HVDC has the goal of reducing the economical distance of HVDC from 100s to 10s of miles, was perceived as an opportunity to economically interconnect communities such as Mountain Village and St. Mary's. The partnership between AVEC and Polarconsult led to a 2007 application to the Denali Commission for a project titled "Polarconsult Small-Scale HVDC". The project is divided into three phases, as follows:

2.1.1 Phase I Summary (2008-2009)

Phase I of this project sought to evaluate the technical feasibility of small-scale HVDC converter technology through a program of design, modeling, prototyping, and testing of a bench-scale converter. In addition, Polarconsult sought to evaluate the technical and economic feasibility of the overall system and estimate the potential savings compared to an AC intertie. The Denali Commission funded Phase I of this project, which was managed by AVEC. This phase successfully laboratory-tested a prototype 250 kW 12.5 kV HVDC converter, designed, constructed, and tested by PPS, confirming that the technology met key performance benchmarks. Phase I was completed in 2009.

2.1.2 Phase II Summary (2010-2012)

Given the successful completion of Phase I, the Denali Commission approved funding for Phase II of the project. The goals of Phase II were to complete full-scale prototyping, construction, and testing of the HVDC converters and transmission system hardware. The end goal was to finalize system designs and construction techniques, and verify construction costs. Before project activities commenced, grant management was assigned to the Alaska Center for Energy and Power (ACEP). This adjustment was made through the mutual agreement of the Denali Commission and AVEC, in recognition that this project qualified as an emerging energy technology. For this reason, The Denali Commission assigned it to ACEP along with additional emerging energy projects recently funded under the Emerging Energy Technology Grant (EETG). In addition, a Stakeholder Advisory Group (SAG) was created, consisting of key technology experts and stakeholders focused in Alaska and provided guidance and feedback on project activities and findings.

Under Phase II, PPS was again selected by Polarconsult to develop, construct, and test prototype-scale converter units suitable for eventual field demonstration in Alaska. Working with the SAG, AVEC, and PPS, Polarconsult specified a 1 MVA converter for a 50 kV DC transmission system, consisting of two 500 kVA modules. These units were designed, constructed, and tested at PPS's facility in New Jersey. In addition, Polarconsult focused on additional transmission infrastructure cost-reduction potential for using HVDC. This culminated in the construction and field testing of an innovative transmission pole design in Fairbanks, Alaska.

2.1.3 Phase III Summary (Proposed)

The final phase of this project, Phase III, is currently in concept form. Polarconsult has proposed to bring the two converters constructed under Phase II to Alaska for field deployment and demonstration. Original concepts called for the construction and demonstration of a full system, complete with the innovative pole design developed by Polarconsult. However, input from the SAG and other project stakeholders narrowed the final scope to a demonstration of the converters on an existing transmission system. Polarconsult has been in discussion with potential partners, including Golden Valley Electric Association, to identify a possible demonstration site. Per outcomes of Phase II, PPS has been reconfiguring and preparing the converters for shipping and field deployment. Due to reduced federal funding, the Denali Commission was unable to continue sole-funding of the project. Funding for Phase III is actively sought by Polarconsult. Polarconsult intends to take the recommendations of this report under consideration in finalizing the proposed work plan for Phase III.

3.0 Technology Background Information

3.1 HVDC Technology Overview

HVDC is a power transmission system that uses DC instead of AC as a means to transmit bulk power; DC is a constant current while AC alternates polarity at a targeted frequency. AC power is the standard format for end-point usage in the United States. Power is delivered to homes, businesses, and industries as AC, and most electrically powered devices are designed to operate from AC power. In contrast, electrical appliances that do not plug into a wall socket are generally powered by DC. For example, batteries generate DC power; common examples include flashlights, smoke detectors, and other battery-powered household devices. During the initial development of AC and DC power in the 1890's, the two standards were in competition for widespread deployment, a situation that came to be known as the "War of Currents". The history of the dominance of AC instead of DC power is discussed in greater detail in [1]. One of the practical reasons that AC won the "War of Currents" over DC is the ease and low cost with which power can be stepped down from high-voltage transmission lines and reduced to the desired end point voltage at delivery using simple AC transformers. High-voltage transmission is used to reduce line loss. During power transmission there is always some line loss, which is an electrical analog to mechanical friction. The amount of line loss is given by:

$$P_{LOSS} = (P_{TRAN}^{2}R) / V^{2}$$

where P_{LOSS} is the power loss in the transmission line, *R* is the electrical resistance of the line, and *V* is the voltage. P_{TRAN} is fixed by the usage demands of the community. *R* is a property of the wire. While *R* can be improved by material selection and by using larger diameter wires, it can only be improved incrementally. The most effective way to reduce line loss is to use high voltages. Line losses decrease in proportion to voltage squared, so if the value of *V* doubles, the line loss decreases by one fourth, and so on. Thus, high-voltage transmission is necessary to keep losses from becoming prohibitively high. Both AC and DC transmission over long distances use very high voltages, typically on the order of 100s of kVs.

At greater distances, DC transmission generally has lower overall losses than AC transmission at comparable voltages. This is because when an alternating current is present, the inductance (*L*) and capacitance (*C*) of the wires becomes nontrivial. Inductance refers to a conductor's accumulation of a voltage when a change in current is applied. Capacitance is the ability of a conductor to store static electric charge when a voltage is applied. In an AC circuit, the cycling currents and voltages result in the line having impedance which includes both real (resistance) and reactive (inductance and capacitance) components yielding real and reactive power loss, respectively. This results in an AC current that is out of phase with the AC voltage, and therefore, increases the losses in the transmission circuit. This loss is exacerbated over long distances. In contrast, the only losses in DC power transmission are due to resistive losses.

The question of whether to use AC or DC for high-voltage power transmission is often primarily an economic one. HVDC transmission infrastructure per mile is less expensive than AC. This is due to the ability to use fewer wires, which results in less weight and thus the ability to space support poles farther apart from each other. However, in HVDC transmission, two additional system components are required: a rectifier, which converts AC to DC, and an inverter, which converts DC to AC. These extra components result in an additional cost for conversion. Therefore, AC is generally less expensive up to a certain distance. That economic distance changes as technology advances and material prices fluctuate. For today's existing HVDC technology, it is on the order of 100's of miles.

In addition to the elimination of reactive power loss (Q_{LOSS}) over long distances, other reasons to select HVDC power transmission exist, including increased power per area taken up ("right-of-way") (because of the reduced infrastructure requirements), reduced environmental impact (fewer support structures to disturb sensitive habitat), and connecting between asynchronous AC systems.

In the late 1880s, when electrical power distribution was first becoming commercialized, AC won dominance over DC for a variety of reasons, many of them political [1]. However, technical motivations for choosing AC also existed. At the time, DC could not be produced at high voltages which meant that large line losses associated with DC transmission occurred. Furthermore, AC voltage could easily be stepped down at the distribution locations using transformers, whereas DC voltage transformation was and remains more technically challenging at the distribution point.

With the development of high-voltage valves (or switches) that allowed DC transmission at high voltage, and thus reduced line losses, DC power transmission became economically competitive with AC power transmission in the mid-20th century. Many large-scale DC power delivery systems exist today, including interties from China's Xiangjiaba Dam 750 miles (1200 km) to Shanghai, from the Brazil's Itaipu Dam 500 miles (800 km) to Rio de Janeiro, and from the wind power farms on the southern tip of the island of Gotland, Sweden 44 miles (70 km) to the city of Visby [3]. New HVDC power transmission systems are being proposed and installed at an increasing rate. Most new construction projects are in China and Europe, but at least 25 are planned for the United States. Most recently, in May 2012, the Federal Energy Regulatory Commission (FERC) approved construction of an HVDC intertie from a wind farm in Northwestern Iowa 500 miles (800 km) to Chicago, with construction to start in 2014 [4]. One of the oldest systems in in the US is a 400kV HVDC line running 435 miles (700 km) from Coal Creek Station, North Dakota's largest power plant, to the Dickinson Converter Station in Buffalo, Minnesota. It has been in operation since 1978 [5].

The following table provides a summary of today's DC power transmission systems and scales:

DC Scale	Converter Type	Power Range (MW)	Voltage Range (kV)	Technology Readiness
Large-scale, high-voltage	Line-commutated converter (LCC)	≈100s-1000s	≈100s	Broad usage; stable and mature technology
	Voltage source converter (VSC) + insulated-gate bipolar transistor (IGBT)	≈100s-1000s	≈100s	Increasing usage with broad adoption; recent and still-developing technology
Small-scale, lower-voltage	Voltage source converter (VSC) + insulated-gate bipolar transistor (IGBT)	≈10-100s	≈10s-100s	Limited usage; new and rapidly evolving technology; ABB, Siemens, and Alstom all offer commercial packages.
	Voltage source converter (VSC) + insulated-gate bipolar transistor (IGBT)	<10	≈10s	Not yet in use; technology under development

Table 1: DC Power Transmission Systems and Scales

3.1.1 Line- Commutated Converters

The world's first commercial HVDC transmission line, built in 1954 to bring power from mainland Sweden to the island of Gotland, used mercury arc valves for current conversion. Mercury arc valves remained the standard conversion technology until the mid-1970s. At that time, solid state devices, usually thyristor valves, took their place. Both of these older technologies use the AC power system circuit to commutate the current, making them Line-Commutated Converters (LCCs). LCCs require rotating synchronous machines in the AC systems, which means power cannot be transmitted to a passive load. An additional limitation to LCCs is that they only offer a single degree of freedom, which is set by how the thyristor is turned on. However, LCC-based HVDC technology still offers the highest line capacity and efficiency of presently available commercial technologies.

3.1.2 Voltage Source Converters

Today, the dominant technology uses Voltage Source Converters (VSCs). VSCs use a relatively new switch technology called Insulated Gate Bipolar Transistors (IGBTs) in a VSC configuration, each with a specific design proprietary to its respective company. The primary advantage of IGBTs over thyristor valves is that the latter requires a pair of large rotating machines (either generators or synchronous condensers) on the AC side at both ends of the transmission system. Thyristors in LCCs also depend on the AC power system circuit to commutate the current. VSCs, on the other hand, have their own control system to regulate the voltage and current output to suit the needs of the system instead of balancing those needs against the needs of the AC power circuit. [6]. In addition, because VSCs do not require any driving system voltage, they can build up a three-phase AC voltage via the DC converter and provide black-start capability [7].

3.1.3 Commercial Small-Scale HVDC Technology

Today, HVDC transmission at lower power and voltages is under rapid development.[1] Three commercial medium-scale HVDC packages (on the order of 10-100s MWs) are currently available:

- HVDC Light, by ABB
- HVDC PLUS, by Siemens
- HVDC MaxSine, by Alstom Grid

Although the exact configuration of the IBGTs varies from vendor to vendor and even within each vendor with time as development progresses, all three systems use VSCs with IGBTs.

Of the three commercially available HVDC packages, HVDC Light was the first to enter the market, and has the largest number of installations worldwide. HVDC Light was developed and introduced in 1997 by ABB, a Swiss company that designs power and automation technologies. HVDC Light transmits power in three phases. The converters use a set of six valves, two for each phase. The control system for the valves uses pulse width modulation (PWM) to switch the IGBTs on or off at a specific duty cycle to control the output voltages and currents on the AC side [8].

ABB also manufactures its own single-pole cables of extruded polymer (paper insulated cables were used in older HVDC technologies) as part of the HVDC Light system. These cables can also be buried.

Examples of HVDC Light Installations in the world include:

- A 50 MW line from a wind farm to the load center in Gotland, Sweden, installed in 1999.
- Three 60 MW lines spanning 242 miles (390 km) from New South Wales to Queensland, Australia, installed in 2000 under a project called Directlink.
- A 220 MW interconnector between the Riverland in South Australia and Sunraysia in Victoria, called the Murraylink and enabling electricity trade in both directions.
- An 8 MW line from the Tjæreborg Wind Farm on the west coast of Denmark to the Danish power grid. This line was installed in parallel with an existing AC transmission line, which allows either or both to be used. This was intended as a demonstration project, paving the way for five offshore wind farms of approximately 150 MW each to be installed over the next 30 years. To date, these farms have not been developed.
- A 36 MW back-to-back station (AC-DC-AC) along the US-Mexico border that connects a substation in Eagle Pass, TX to another in Piedras Negras, Coahuila, thus linking the two electrical grids. The purpose is to mitigate possible voltage instability due to load growth in the Eagle Pass area, and also to allow power exchange in both directions.
- The Cross Sound Cable, an underwater link between Connecticut and Long Island, NY.
- The Estlink system, which runs both undersea and underground between Estonia and Finland.

HVDC PLUS is Siemens' mid-scale HVDC package, which competes directly with HVDC Light. One example of an HVDC PLUS installation is the Trans Bay Cable Project. This installation connects the City of Pittsburgh, California with downtown San Francisco via a submarine cable under San Francisco Bay. An HVDC PLUS project currently being developed is a 2000 MW, 320 kV, 40 mile (65 km) interconnect between Baixas, France and Santa Llogaia, Spain, which is expected to be operational by 2013.

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[1] The authors would like to recognize that strictly speaking, "small-scale HVDC" systems are not HVDC systems, given the relatively lower power levels and voltages. For the purposes of this report, however, this technical distinction is not made. In addition, to clarify the "small-scale HVDC" focus of this report, the term "medium-scale HVDC" will be used for small-scale systems on the order of 10 to 100s of MWs, and "small-scale HVDC" will be used for small-scale systems on the order of 1 MW.

HVDC MaxSine, which is the package offered by Alstom Grid, is the newest of the three packages to hit the market. It was only recently awarded its first commercial contract in January 2012. The project by the Swedish utility Svenska Kraftnät totals €240 million (approximately 314 million US dollars). The project is for a 1440 MW South-West Link to connect Barkeryd in Central Sweden to Hurva in Southern Sweden [9]. The project is scheduled to be completed at the end of 2014.

3.1.4 Pre-Commercial Small-Scale HVDC Technology

Small-scale HVDC systems (on the order of 1 MW) are not commercially available and are currently still in the early stages of development. Small-scale HVDC converter technology using VSC and current source converters (CSC) is theoretically the same as the technology used in medium and large-scale systems. However, it is more difficult to build a small-scale converter that is cost effective due to the higher per kW cost for design and construction compared to larger systems. Furthermore, the niche market for these small-scale HVDC converters has kept the big three HVDC manufacturers (ABB, Siemens, and Alstom Grid) from investing in smaller systems when their efforts and revenue have been focused on the medium and large-scale HVDC markets. For more detailed information on small-scale converters and the specific technology developed through this project, please see section *4.0 Small-Scale HVDC Converter Development and Testing*.

Although it has always been costly to power islanded grids with diesel-powered generators, it did not become economically crippling until the last decade’s leaps in diesel prices. This has spurred interest in and development of this technology for Alaska as seen through this project. It should be noted, however, that other industries use small-scale DC conversion in their standard applications and are already mature and may be applicable to the power transmission industry. Such industries which generate DC power include airplanes, trains, naval vessels, offshore wind farms, and offshore oil platforms—particularly in the North Sea.

Another interesting industry occurrence is that in 2010, Advanced Energy, an American company that develops power conversion technologies for both the thin-film plasma and the solar industries, acquired PV Powered, which is an American manufacturer of grid-tied inverters for the solar energy market. [10] This, too, is a fusion that could lead to development of a small-scale converter for HVDC application. PV Powered mass produces inverters on a scale of 250 kW to 2 MW, which are designed for the solar photovoltaic market (photovoltaic panels produce DC power), but may be adapted to HVDC. They also produce micro-inverters that convert the output of individual solar panels to AC at the panel level for connection to local AC grids.

3.2 Multi-Terminal HVDC Networks

At the present time, virtually all HVDC systems are point-to-point—i.e. not connecting multiple generators or end-users—but rather transmitting power from point A to point B. Substantial interest in developing the more complicated technology for multi-terminal (or ‘multi-node’) networks exists, which would link multiple energy users in a region through an HVDC grid. The technical leap from a point-to-point intertie to a multi-terminal grid is nontrivial, but possible within the constraints of existing technology. Nevertheless, there is some doubt within the industry concerning the technical readiness of multi-terminal HVDC networks, including concerns about HVDC circuit breakers and control methods. Both of these points are addressed in some detail and countered in [11]. Several patents covering multi-terminal HVDC technology have been filed, and are listed in [11]-[14].

Multi-terminal AC networks are technologically easy in comparison to DC because power can be easily stepped down at distribution points using AC transformers. However, no easy analogous solution for DC power distribution exists.

Motivations for developing a multi-terminal network within an HVDC system include:

- Combining the economic power of multiple small communities to utilize a resource that is unaffordable to a single community alone on an isolated grid.

- Connecting a distributed grid that uses a renewable, but intermittent, power source (such as solar or wind), to one that uses a steady source.
- Connecting to more than one power supply in case of failure.
- Increasing overall energy availability among otherwise isolated power grids [15].

Given the regional scattering of isolated Alaskan villages, multi-terminal networks are of particular interest to this project. A multi-terminal network could theoretically connect a series of villages, thus decreasing operational costs and increasing efficiency by concentrating power service in one location. Alternatively, a remote renewable resource, such as hydroelectricity, could be connected via a multi-nodal network to several communities within a region.

One example is a proposal to build large offshore wind farms in the North Sea and connect them to the power grids of different nations via HVDC [16]-[17]. In this case, HVDC is advantageous not merely due to cost, but also its ability to handle the inevitable asynchronous connections among different national power grids, and the capacitance of the submarine cable systems.

A few large-scale multi-terminal HVDC networks are already in use worldwide, for example:

- The Hydro Québec – New England transmission line went into service in 1986 and originally delivered power from the Frank D. Comerford Dam near Monroe, New Hampshire to the Des Cantons station near Windsor, Quebec. Due to asynchronicities between the Canadian and American electrical grids, the line was designed to be HVDC. In the early 1990's, it was extended to include the hydroelectric power plants of the La Grande Complex in Quebec and the load centers of Boston and Montreal. A further extension into New Hampshire is currently in planning stages.
- The Italy-Corsica-Sardinia transmission line (SACOI) was originally built to deliver power from mainland Italy to Sardinia. Later, another line was added to connect Sardinia to Corsica.

The following HVDC multi-terminal networks are currently in planning and/or under construction:

- In India, an 800 kV high-voltage direct-current (HVDC) bi-pole transmission line is under construction from Biswanath Chariyali (Assam) to Agra (Uttarpradesh). Two mega hydropower projects coming up in the Kameng and Lower Subansiri basin in Arunachal Pradesh will be capable of generating up to 50,000 MW and will provide power to urban areas with a power deficit. The total length of the transmission line will be approximately 1200 miles (1900 km). ABB is providing the HVDC terminal equipment.
- A company called the Atlantic Wind Connection is proposing the world's first offshore multi-terminal HVDC transmission grid. The project plans to deliver energy produced by offshore wind farms off the Eastern seaboard of the United States. It claims that "The Mid-Atlantic region offers more than 60,000 MW of offshore wind potential in the relatively shallow waters of the outer continental shelf," and envisions a multi-terminal HVDC grid to "connect up to 7,000 MW of offshore wind, enough power to serve approximately 1.9 million households." [18] The grid is designed to have nine offshore and seven onshore nodes, each with its own voltage source converter station.
- All three major HVDC companies—ABB [19], Siemens [20], and Alstom [21]—have advertised their abilities to create multi-terminal networks to bring power to the local electricity grids from large offshore wind farms in the North Sea. These specific project proposals are yet to be realized.

Of note, General Electric is also developing electricity transmission hardware specifically intended to bring energy from remote renewable generation sites to the grid. Funded by a $4.5 million grant from the United States Department of Energy, through the Advanced Research Projects Agency--Energy (ARPA-E), General Electric looks to develop hardware and software under the project title "Resilient Multi-Terminal HVDC Networks with High-Voltage High-Frequency Electronics" [22].

3.3 Single-Wire Earth Return (SWER)

SWER is a means to transmit power using a single wire for transmission and the earth (or sea if the cable is undersea) as a return path, in order to close the circuit so that current (power) may flow through it. The primary goal behind this is cost reduction; another is reducing environmental impact. Because a voltage difference is imposed on the ground, concerns exist about safety to people, animals, and buried structures. A common concern is that the ground currents could increase corrosion rates of pipelines and buried utilities.

SWER was proposed for applications in Alaska by Polarconsult because while HVDC alone can potentially reduce electricity costs in rural Alaska, HVDC in conjunction with SWER has the potential to reduce the costs more than HVDC alone. Capital costs for installation of a SWER line can be as low as half those of an equivalent 2-wire single-phase line [23]. Moreover, rural Alaska has a population and energy structure that lends itself well to SWER—a low-density, widely scattered population and very little buried infrastructure in areas in between population centers.

SWER was first developed in the mid-1920s by engineer and inventor Lloyd Mandeno for use in rural New Zealand [24]. Since then, SWER usage has expanded. Australia has since developed a standard that has since been adopted in New Zealand as well as in developing regions in Africa, South America, and Southeast Asia [25]. Other regions that have adopted SWER for remote power transmission include the Canadian province of Saskatchewan, Brazil, and the United States' upper Midwest. Earth return has not been used exclusively in DC applications; many modern SWER applications are in fact AC. However, SWER is often considered in conjunction with HVDC where cost minimization is paramount.

SWER is typically used where cost reduction is a high priority and where there are few buried underground structures whose structural and functional integrity may be compromised by the ground return current. These two conditions tend to occur in rural areas or in developing nations. The following are examples of countries with currently installed SWER systems.

- Australia
  - In Australia, SWER AC power distribution is widely used, with over 124,274 miles (200,000 km) operating at 19.1 kV or 12.7 kV in seven states. [26]
  - SWER is so well established in Australia that the power company of Ergon Energy is using its Wambo Creek SWER line as a test bed for a number of devices designed to improve the reliability of the rural power supply. Ergon Energy maintains about 40,000 miles (65,000 km) of SWER, some of which is approaching voltage and capacity constraints. However, it is not economically feasible for them to upgrade to conventional 3-phase AC transmission. Some of the technologies undergoing testing at Wambo Creek are battery storage for use during peak loading times and different devices to regulate voltage and control voltage stability. [27]
  - The HVDC Basslink crosses the Bass Strait, connecting the Loy Yang Power Station in Victoria, on mainland Australia, to the George Town substation on the island of Tasmania.
- New Zealand
  - New Zealand has a well-established AC SWER standard [28] that is based on Australia's, which was in turn based on the original usage within New Zealand itself. The New Zealand Electricity Engineers' Association also offers a "Guide for High Voltage SWER Systems". [29] Over 93,000 miles (150,000 km) of SWER line are in service in New Zealand today. [30]
- Canada
  - SaskPower, the principal electric utility company in Saskatchewan, is responsible for electrifying the province's rural areas under The Rural Electrification Act of 1949. It integrated the majority of the province's localized, independent municipal electrical utilities into one unified grid. This brought electricity to over 66,000 farms between 1949 and 1966. AC SWER was largely used and, at the time, was one of the largest SWER systems in the world. [31]

    - In addition, approximately 4300 miles (7000 km) of SWER line are in active service in Manitoba. [32]
- Laos
    - Laos uses SWER with single-phase AC in the southern and central regions of the country (in the north, there is a system that uses shield wires, which are conducting wires that hang above the transmission wires). Electricité du Laos, the state corporation that owns and operates the national electrical system, has implemented 84 miles (135 km) of SWER line on six SWER projects in as many provinces. [23]
- Cambodia
    - Cambodia is expanding its electricity network using SWER with single-phase AC in rural areas, under the Rural Electrification and Transmission Project [33]. The national target is for 60% of the country to have electricity access by the year 2020. [23]
- Mongolia
    - In 2009, it was announced that the Asian Development Bank, a regional development bank whose aim is to facilitate economic development of Asian countries, was partnering with the government of Japan to fund a pilot project to bring power to rural regions of Mongolia. [34],[35] Mongolia, like Alaska, is large, sparsely populated, and largely dependent on diesel-generated power. The project intends to build transmission and distribution lines to nine small population hubs using single-phase AC SWER. It is intended to be a pilot project, with the intent of paving the way for others to follow.
- South Africa
    - Eskom Distribution, South Africa's primary electricity provider, has an AC SWER standard in place that addresses both grounding and connection to the grid [36].
- Tunisia
    - In Tunisia, use of AC SWER resulted in a cost reduction of 26-30 percent of the cost for equivalent two-wire single-phase systems. [23] Tunisia developed its own unique combination of single-phase and three-phase distribution called Mise à La Terre (MALT) which translates as set to earth or ground. [37]
- Namibia
    - Caprivi Link, an HVDC Light project commissioned in Namibia in 2010, is a 600-mile (950 km) 300 MW, 350 kV DC line that will connect the electrical grids of Namibia and Zambia. [38] It will operate initially as SWER, and then be upgraded to a bipolar system at a later date.
- Mozambique
    - In Mozambique in 2009, the electrification rate was 20% of residents in urban areas and under 2% in rural areas [26] In 2006, the U.S. engineering firm of AECOM was commissioned to formulate a Low Cost Rural Electrification Plan (LCREP) for Electricité de Moçambique, with the goal of bringing electricity to 20% of the nation's population by 2020.
    - Due to the low population density in rural areas, single-phase AC SWER was determined an appropriate technology to bring power to these regions. Leveraging the knowledge and engineering standards gained from SWER projects in neighboring South Africa and Namibia, Mozambique is using two SWER systems to supply electricity to the villages of Mavila and Morrungula in the Inhambane province. Spurs of 19.1-kV AC SWER line were constructed from extant 33-kV three-phase overhead lines in rural areas as the first stage of LCREP.
- Brazil
    - In Brazil, SWER is called "Redes Monofilares com Retorno por Terra", or MRT, and is used extensively on AC lines. Brazil has developed its own detailed standards and drawings that are publically available via the website of Brazil's electricity distributor, Celpa.

SWER is also used in India, Vietnam, and Burkina Faso. SWER is legal in Sweden, but it is unknown how extensively it is used. SWER was introduced to Botswana in the 1990's, and was has been recommended for large expansion

[39]. SWER is also used for undersea cables, including the Australian Basslink (mention above), the HVDC Baltic Cable that runs under the Baltic Sea and connects the power grids of Germany and Sweden, and the HVDC Kontek, a 106-mile (170-km) long 400kV DC cable that connects the German power grid with that of the Danish island of Sealand.

4.0 Project Review: PPS Converter Development and Testing

The primary project activity for Phase II was the development of a full-scale prototype HVDC converter system to validate the design and functionality of the system. This activity builds on the successful construction and demonstration of a bench-scale prototype 250 kW 12.5 kV HVDC converter in Phase I.

As with Phase I, the full-scale prototype was designed, constructed, and tested by PPS at its facility in Princeton, New Jersey. The key power parameters for the full-scale prototype were specified by Polarconsult and developed with the input of the SAG. The result was a 1 MVA converter for a 50 kV DC transmission system, consisting of two 500 kVA modules.

Some of the desired operational functionalities of the PPS converter to be discussed in this section, such as bidirectional, multi-terminal, real and reactive power control, and voltage regulation, have been demonstrated on an individual basis, but never before in a single converter technology.

The following section is a review by ACEP of the PPS converter technology and the development and testing of the prototype, resulting from site visits conducted during development and testing, a study of design and construction documents, and a review of Polarconsult and PPS reporting. A discussion of subsequent barriers to deployment in rural Alaska is included.

4.1 PPS Converter Technology

The PPS AC/DC converter uses a series resonant configuration to convert three-phase 480 VAC at 60 Hz to 50 kV DC for HVDC transmission and vice versa. The converters are bidirectional, meaning that power can flow in either direction working as either a rectifier or an inverter. The converters can operate in one of two modes depending on the direction of power flow and the state of each AC grid as follows:

1) Current source converter (CSC) in grid-tied mode regulating current to a village load, or
2) Voltage source converter (VSC) in microgrid mode regulating the AC system voltage.

In CSC mode, the converter regulates the current to the AC load while maintaining a constant voltage. In VSC mode, the converter regulates the AC system voltage for any level of load current up to the rating of the converter.

The general layout of the PPS converter is illustrated in the block diagram in Figure 1.

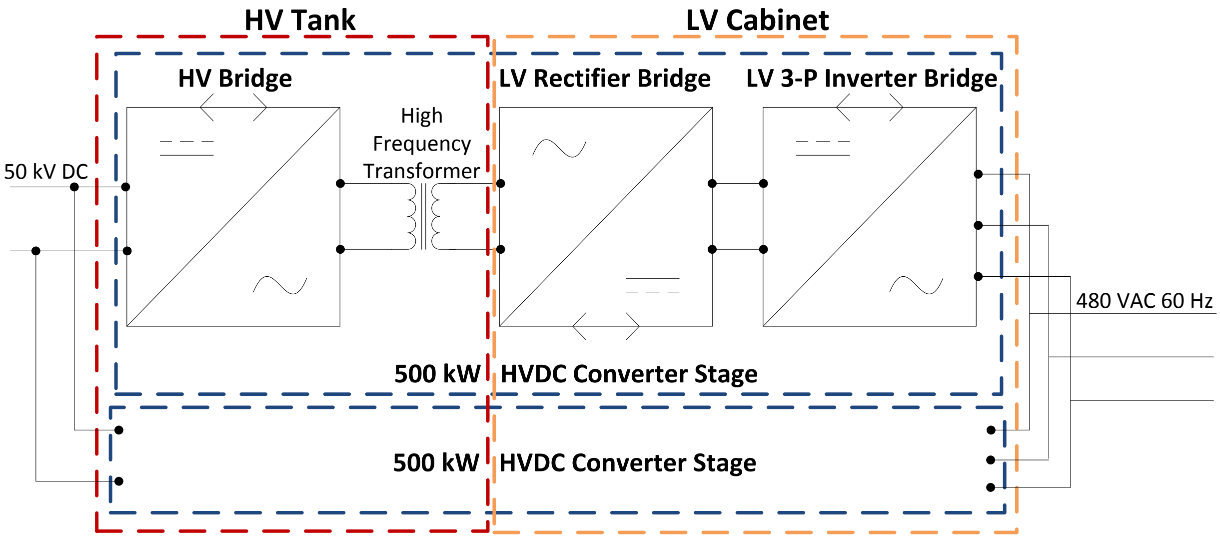

Figure 1: General PPS Converter Block Diagram

Each converter has four basic stages consisting of three bridges and a high-frequency (HF) transformer divided into a high-voltage (HV) tank and a low-voltage (LV) cabinet. These features are described as follows for the inversion mode (HVDC to LVAC) of operation:

HV Tank (Luminol Oil-Filled):

1) HV Bridge: Conversion of HVDC (50 kV DC) to HVAC (37 kV AC) at 8 kHz.
2) High-Frequency Transformer: Conversion of HVAC (37 kV AC) to LVAC (800 V AC).

LV Cabinet:

3) LV Rectifier Bridge: Conversion from LVAC (800 V AC) to LVDC (800 V DC).
4) LV 3-Phase Inverter Bridge: Conversion from (800 V DC) to 3-phase 480 V AC at 60 Hz.

Each converter consists of two parallel 500 kVA converter stages for a total power rating of 1 MVA as illustrated in Figure 1. The 1 MVA rating is based on the general load profiles for a number of rural Alaska villages. Two 500 kVA modules are required on each end of the transmission line to convert low-voltage AC (LVAC) at Village 1 to HVDC (rectifier: AC to DC conversion), transmit up to 1 MW of electric power over a HVDC transmission line, and then convert HVDC back to LVAC at Village 2 (inverter: DC to AC conversion) as illustrated in Figure 2. The system can work in reverse if power flow is in the opposite direction. Therefore, each converter is bidirectional with possible operation as a rectifier or inverter [20].

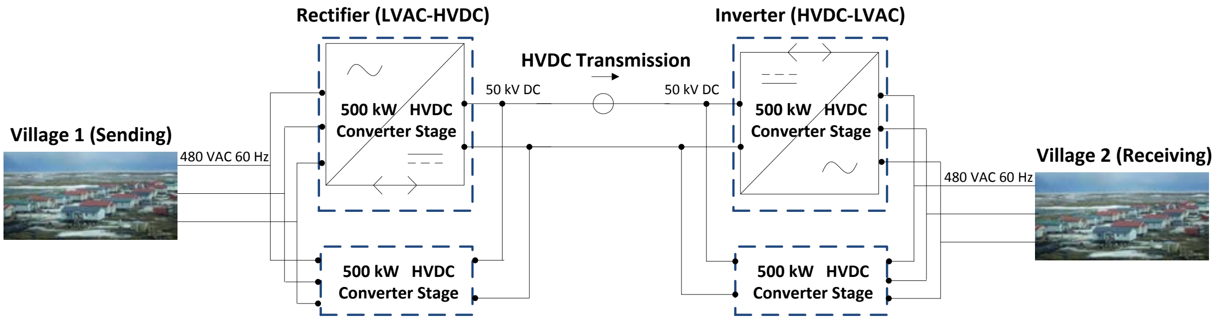

Figure 2: Layout of Converters in HVDC Transmission System between Two Villages

Each of the three bridges consists of insulated gate bipolar transistors (IGBTs) (symbol:) acting as switches for inversion and diodes (symbol: —▷|—) for rectification as shown in Figure 3 with the converter in rectifier mode (480 V AC three-phase to 50 kV DC). The main difference between the operation of these two devices is that, as with any solid-state transistor, switching the IGBT on and off can be controlled using a triggering signal, while switching the diode on and off is dependent on the voltage level applied across the diode being larger than the forward voltage rating of the diode junction. The triggering signal for the IGBT is typically a square-wave pulse with a specific or variable width generated using a pulse-width modulation (PWM) scheme at switching frequencies in the range of 1–10 kHz for MW scale applications. The voltage and current ratings of IGBTs decrease as the switching frequency increases to prevent thermal runaway.

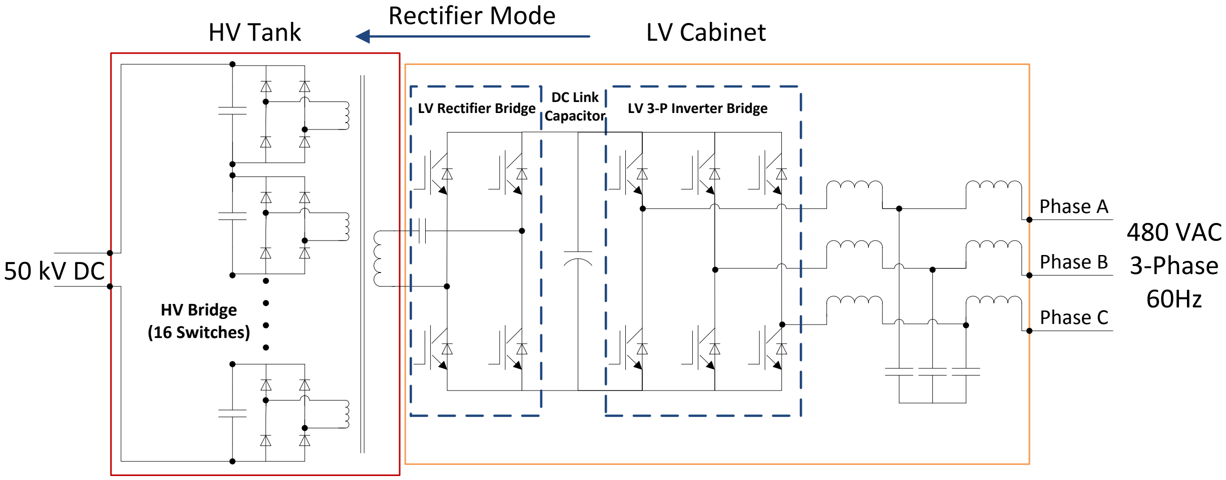

Figure 3: PPS Converter in rectifier mode (AC to DC) showing basic layout of IGBTs and diodes

With the PPS converter in inverter mode, the IGBTs in the HV tank are switched at 8 kHz using a PWM scheme through an optical feedback signal from voltage and current sensors to regulate the voltage and current. The PWM technique is based on the control signal, which is typically DC level, square wave, or sinusoidal. In this case, a PWM technique is used in a feedback loop to generate a trigger pulse to turn on the IGBTs by comparing the magnitude of an 8 kHz carrier signal (triangle waveform) to a control signal (DC level) over time as shown in Figure 4. A PWM trigger pulse is generated when the value of the triangle waveform is greater than the DC level.

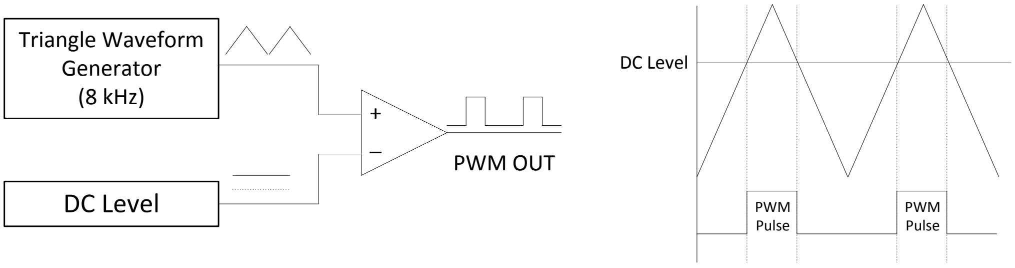

Figure 4: PWM Control Scheme and Typical Waveforms for IGBT Triggers

Triggering or commutation of the IGBTs between bridge pairs in each leg of the converter produces a single-phase or three-phase output, depending on the bridge configuration. Commutation is defined as the transfer of unidirectional current between the rectifier circuit elements (diodes) or converter circuit elements (IGBTs) that conduct in succession. In other words, commutation is the process of transferring from one switch pair to the next to achieve the desired output signal. This process can be thought of as similar to having three banks of lights on separate switches that switch on and off in consecutive order, similar to theatrical lighting. The commutation interval for switching states is usually very short in order to eliminate losses, but also long enough to allow previous switch pairs to turn off before the next switch pairs turn on to avoid short circuiting the DC bus.

One of the primary adverse results of the PWM switching scheme is the introduction of noise or harmonics at frequencies other than the desired frequency (60 Hz on the AC side for inverter mode). Harmonic voltages and currents are generated at multiples of 60 Hz with magnitudes that are generally less than the fundamental magnitude. Therefore, it is advantageous to have less of the lower-order harmonics. For a three-phase inverter, the odd multiples of the third current harmonic or triplen current harmonics (3, 9, 15, 21, …) cancel each other because the summation of the three phases of current at those frequencies is zero. This concept is illustrated by the Phase A current and the current harmonics spectrum plot for a basic six-pulse three-phase inverter circuit in Figure 5.

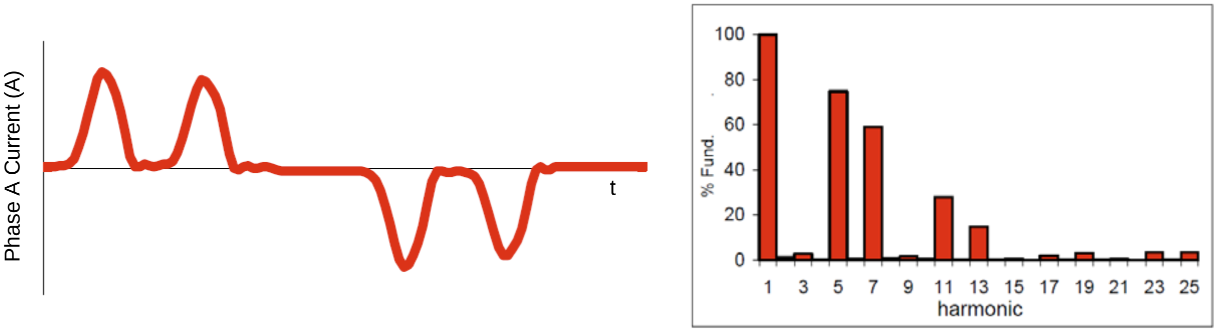

Figure 5: Sample Phase A Current and Harmonic Spectrum from a Generic Three-Phase Inverter Circuit

A typical measure of the level of distortion due to harmonics is Total Harmonic Distortion (THD), which is defined as the ratio of the sum of the powers of all harmonic components to the power at the fundamental frequency (60 Hz in this application). The THD for voltage (THD_V) is defined as:

$$THD_V = \frac{\sqrt{V_2^2 + V_3^2 + V_4^2 + V_5^2 + \cdots}}{V_1}$$

The THD for current (TDH$_I$) is determined by simply replacing the voltages (V_1, V_2, V_3, V_4, V_5, …) with currents (I_1, I_2, I_3, I_4, I_5, …).

A standard known as the IEEE 519 develops THD limits for voltage and current based on system load conditions. Princeton Power Systems tested its converter components for harmonics, but not with a full load and with limited functionality from the HVDC to three-phase LVAC side, and vice versa. To develop the converter into a fully functional device, a thorough harmonics analysis will need to be implemented under a full range of load conditions.[2]

The use of a HF voltage transformer rather than a 60 Hz voltage transformer normally used to convert voltage levels in AC systems greatly reduces the size, weight, and cost of transforming to high voltages. This effect occurs

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[2] The design specification for the PPS converter is less than 5% THD. Simulations performed on the Phase II prototype design indicated THD of less than 1.35% [2] at Appendix F, Attachment F-1.

because the voltage rating of the windings in the transformer is directly proportional to the frequency of the voltage applied to the transformer and the cross-sectional area of the windings, and thus reduces the size and length of wire required for the windings, specifically the high-voltage winding. The windings used in the PPS HF voltage transformer are composed of thin strands of Litz wire to reduce losses due to skin effect (the majority of AC flows outside of the conductors) in conductors used at frequencies up to about 1 MHz. Each thin strand of wire is insulated and woven together with other strands in a pattern that equals the proportion and overall length of the outside of the conductor, thus reducing the skin effect [40].

Another important feature of this VSC HVDC converter system is that the 500 kVA converter modules can operate independently to better match system power-transmission levels, as the peak converter efficiency occurs for operation at or near rated power. This type of a modular converter system is typical of those used on naval ships for onboard power and propulsion systems, hybrid vehicles, diesel electric railroad engines, and large draglines in mines, and for conversion from AC to DC for large industrial processes like aluminum smelting. The concept, referred to as Power Electronic Building Blocks (PEBBs), consists of two or more converter blocks in a single compact unit that can operate independently or together to better match the power level of the system for higher converter efficiency. A PEBB converter incorporates smart controls that can sense the type and operational state of the source and load to which it is connected. This smart functionality allows for adaptive reconfiguration of the controls, which is highly desirable for hybrid systems.

The HVDC VSC technology also allows for possible multiple connections along the HVDC line, referred to as a multi-terminal DC (MTDC) system. The system requirements for a MTDC system specific to the PPS converters are as follows [41]:

1) common standard DC voltage bus for all converters
2) independent bidirectional operation and real/reactive power control of each converter
3) DC side transmission line fault detection and isolation
4) detection and isolation of single faulty converter without de-energizing all converters
5) detection and isolation of DC bus faults
6) auxiliary power (DC battery) for black starts of converter
7) optimal power flow through SCADA and communications between converters

Although all the requirements listed above are necessary for MTDC operation, items 1, 2, 6 and 7 are very important to the design of the PPS converter for Alaska. In the PPS system, each converter must be connected to 50 kV DC voltage. Voltage ratings of all DC equipment connected to the system would need to be standardized at this level, as equipment with a higher DC voltage rating would be too costly.

Additionally, each converter must be able to operate independently with bidirectional operation and real/reactive power control. This requirement is of particular importance in a system connecting rural communities in Alaska, with diesel electric and wind generation and loads coming on- and off-line, and therefore, the need to change the direction of power flow and the control mode depending on the state of the system. In this sense the VSC terminal can act as a current source to provide power to a load or a voltage source to regulate AC voltage to a microgrid. The VSC should be able to turn on and off in a MTDC system under a full range of loads, with the VSC in inverter mode acting as a generator for the following four scenarios:

1) Turn on in parallel with existing generation
2) Turn off existing generation and use VSC to provide power to a load
3) Turn on generation in parallel with existing VSC
4) Turn off VSC with generation online

The VSC should be able to operate both independently and in combination with other converters in an MTDC system. There are four basic control modes for each converter that depend on the direction of flow and the need for real or reactive power control with only two functions controlled in any given converter at a time.

The control modes are:

1) Control real input power, P (kW)
2) Control reactive input power, Q (kVARS)
3) Control DC terminal voltage (rectifier)
4) Control AC terminal voltage and frequency (inverter as isolated generator)

Each converter in the system operates with two of these control modes at any given time to supply real or reactive power and control DC or AC voltage. At least one converter in the MTDC system must operate in mode 3 with controlled DC terminal voltage to regulate DC bus voltage to account for DC voltage droop. Specific to rural Alaska, the VSC in mode 4 will need to be able to operate in parallel with diesel controls in AC voltage droop (lag) mode and possibly in AC voltage rise (lead) mode given the existence of excitation systems like synchronous condensers and capacitor banks in hybrid wind-diesel systems.

With this description of the basic technology framework for the design and control of the PPS voltage source HVDC converter, the development and testing of the PPS converter to date will be discussed next.

4.2 PPS Converter Development & Testing

The PPS converter development consisted of designing the two low-voltage bridges, the one high-voltage bridge, the high-frequency transformer, and the cabinets/enclosures with proper cooling, all to meet voltage, power, size, and weight specifications for deployment in rural Alaska. The technology of the two low-voltage bridges, one high-voltage bridge, and the high-frequency transformer was described in Section 4.1. The high-voltage bridge and high-frequency transformer are in a Luminol oil-filled high-voltage tank, while the low-voltage bridge is in a low-voltage cabinet.

Each major component—the HV Bridge, High Frequency Transformer, and LV Bridges—were designed by PPS. The construction of the cabinets, high-frequency transformer cores, and windings was contracted out to manufacturers and suppliers based on PPS designs.

The overall converter was tested for functionality in both rectifier and inverter mode under low power to verify the control schemes and voltage levels with results, as shown in Figure 6.

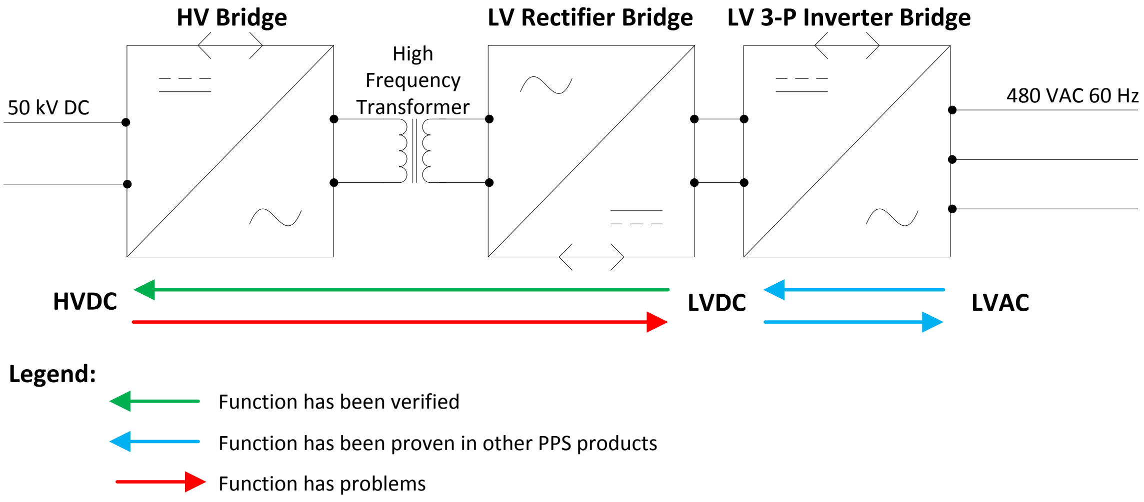

Figure 6: Functionality of Converter as Tested in Rectifier and Inverter Mode

The converter was tested in rectifier mode with the HV tank in open air at lower voltage and filled with Luminol oil at full voltage. The converter was demonstrated during a site visit on November 14, 2011, to function in rectifier mode producing 50 kV DC from 3-phase 480 VAC, but under low power conditions due to limited loading capability at the PPS lab. The converter was also tested in inverter mode at very low power conditions (essentially no load) to demonstrate the voltage and current control concepts discussed in Section 4.1. Testing of the inverter mode of operation was limited due to hardware issues with the optical trigger circuit and the IGBTs in the HV cabinet, which will now be discussed in detail. The functionality of the LVAC/LVDC bridge has not been verified in this specific converter.

During the course of testing the converters at PPS, three significant hardware issues were encountered, the latter two of which prevented a fully operational converter in inverter mode at the given power requirements. The three issues were as follows:

1) Leakage along a taped seam on the cylindrical core insulation wrap of the high-frequency transformer, causing an arc during open-air hi-pot testing at 11 kV.

   A glow behind the windings of the high-frequency transformer was identified during high-potential testing caused by the failure of the Dupont Kapton polyimide tape to provide enough insulation, as illustrated in Figure 7. Testing in open air is an extreme situation, particularly at high voltages, because air provides an arcing path with much less resistance than an oil bath. Additional strips of polyimide tape were placed along the seam to reduce the leakage, and the test was repeated with no arcing present. Arcing between the transformer case and leads, extending from the secondary winding of the transformer to the mounting brackets on the top of the transformer, was identified and solved by repositioning the wires.

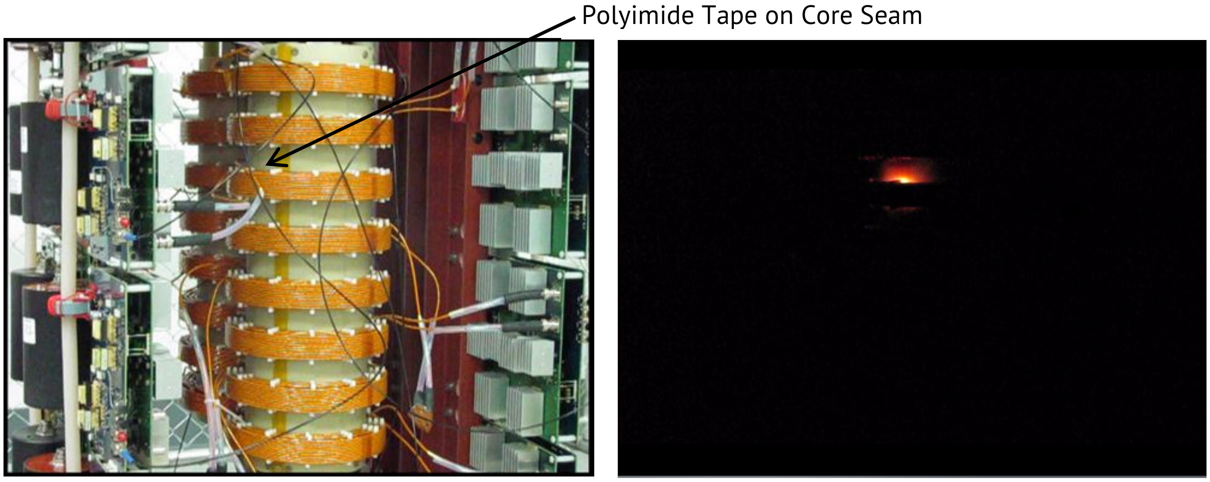

Figure 7: High-Frequency Transformer During Testing on August 5, 2011: (left) Transformer Core and Windings Showing Taped Seam, and (right) Arcing During Open Air Testing

2) Loss (noise) in the optical triggering system for the IGBT switches in the high-voltage tank causing timing issues.

   A fiber optic network used to send triggering signals from the sensor feedback loop to the IGBTs in the high-voltage tank exhibited timing problems due to losses in the triggering signals. Significant signal loss (noise) was identified through the fiber optic lenses that relay optical signals at specific frequencies from the optical fiber to the control boards and vice versa. Different lenses were tested and evaluated to resolve the triggering problems, and new lenses were procured by PPS for the prototype 500 kW converters.

3) Thermal runaway of the IGBTs in the high-voltage tank at 8 kHz switching frequency.

   The stack of 16 IXYS IGBT bridges in the high-voltage tank operating at 3.125 kV each (16*3.125 kV = 50 kV DC) experienced thermal runaway with the converter in inverter mode (DC-AC). This occurred mainly because the 4 kV, 100 A, and 8 kHz ratings of each IGBT are not simultaneous ratings. Princeton Power Systems reported testing the IXYS IGBTs demonstrated thermal runaway when switching 1 A of current at 3000 V and 1 kHz, well below the 4 kV, 100 A, and 8 kHz ratings in Luminol oil with conventional cooling as required by the design. These IGBTs will not function in this design in inverter mode (HVDC to LVAC); therefore, a new Powerex 4.5 kV, 150A dual package IGBT was chosen for the HV stack. However, the HV stack needed to be reconfigured, since the new IGBTs have a higher voltage rating and a different form factor (board layout). The new IGBTs also require a long lead time for delivery from the manufacturer, so final converter reconfiguration and testing was delayed until 2013.

These developmental challenges appear to be surmountable through additional design-build-test iterations by PPS, and do not appear to be fundamental problems with the technology. Other barriers to deployment of small-scale HVDC converter systems in rural Alaska are discussed in more detail in the next section.

4.3 Challenges to Deployment in Rural Alaska

Currently, environmental and technological challenges need to be overcome for the successful deployment of the 1 MVA, 50 kV HVDC converters in a SWER transmission system in rural Alaska. Once a fully functional prototype is developed, independent testing of the converters will still be needed to validate efficiency and performance, followed by deployment on an Alaska utility system to validate functionality and reliability in a commercial setting.

Concerns with the PPS converters were identified in May 2010 during a site visit to PPS by ACEP staff, technical consultants, and Polarconsult. The concerns include the following:

1) The HV tank and LV cabinet need to conform to allowable size and weight limits for air transport to Alaska villages. The converter form-factor developed in Phase II allows for major converter components to be transported via a CASA-200 aircraft, which is flown by several rural Alaska carriers and is capable of landing at the vast majority of the state's rural airports.[3]
2) Proper temperature controls around the converters need to be maintained. The converter specification developed in Phase II includes a broad ambient operating temperature range of -30 to + 50°C.[4] Installing the converters inside climate-controlled buildings provides significant advantages, such as improved security and a suitable environment for converter maintenance and repair.
3) The level of controls on the converter does not account for the typical operation of diesel electric generators, with many power on/off cycles, and does not account for the possibility of an unstable renewable power source, such as wind, being used in parallel with diesel electric generation as a backup. This concern is more pressing from a perspective of application to rural Alaska. This concern can be addressed by providing appropriate controls for the converter. As the specifications and functional requirements of such controls are application-specific, they were not provided as part of the Phase II design effort and deliverables.
4) The opportunity of potentially connecting two or more communities and energy resources in a single transmission grid presents a challenge, requiring a multi-terminal DC system, which is technically feasible from the standpoint of using voltage source converters, since a common DC bus voltage is required. However, a converter is required at each point in the system where another community or energy source is integrated into the HVDC transmission grid.

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[3] [2] at Appendix F, page F-33-34

[4] [2] at Appendix F, page F-35

Numerous operational and socio-economic challenges are associated with the deployment of small-scale HVDC converter technology in a relatively limited niche, including operation and maintenance and human capital costs. Operation and maintenance costs are largely dependent on converter reliability, which is at best a guess given that the reliability of individual components are known, but that a fully functional converter has not been developed. The PPS converter was designed to have a mean time between failures (MTBF) of 5 years with a 50-year design life. Reports on the MTBF from an analysis conducted by Amorosa Reliability Associates on the PPS converters found a MTBF of 3.6 years with a 26-year design life largely due to low MTBF (10 months) for the 16 HVDC transformer boards. A MTBF re-analysis was performed based on the inclusion of the new Powerex IGBT modules and redesigned HVDC transformer boards, resulting in a MTBF of 6.2 years with a 51.3-year design life, meeting the design criteria of a 5-year MTBF with a 50-year design life.

5.0 Project Review: Feasibility of HVDC Transmission

The secondary project activity for Phase II was an investigation of the construction methods necessary to make HVDC systems economically deployable for rural Alaska applications. Specifically, this activity focused on investigating two transmission scenarios:

1) Rural Utilities Service (RUS) Design Approach, Modified to HVDC Interties
2) Alaska-Specific Design Approach for HVDC Interties

Polarconsult developed and evaluated conceptual overhead transmission line designs for each scenario. Of particular note, in support of investigating Scenario #2, Polarconsult conducted a field demonstration of several components of developed transmission infrastructure, including an innovative pole design.

This report provides a review of the key elements of this project activity. A review of Scenario #1 is conducted through an economic analysis and a review Scenario #2 is conducted through a review of field demonstration activities. In addition, overview information of the two scenarios and a review of a key concept shared by both scenarios, SWER, are provided.

5.1 Overview of Transmission Scenarios

The two conceptual transmission scenarios developed and evaluated by Polarconsult assumed a capacity to supply 1 MW at 50 kV DC, per the design specifications of the converters. Both scenarios considered three HVDC transmission circuit configurations:

1) Monopolar SWER
2) Monopolar two-wire transmission with metallic conductor-return path
3) Bipolar two-wire transmission

For each scenario, Polarconsult developed and evaluated conceptual overhead transmission line designs considering site-specific conditions, codes, utility and lender requirements, construction methodologies, standard design practices, and project economics. Comprehensive design and evaluation documents can be found in [2]. The following is a summary of the two scenarios.

5.1.1 RUS Design Approach

The premise of the first scenario was to begin with currently accepted industry practice in designing and constructing transmission lines in rural Alaska, and modifying them for HVDC use. This scenario was developed using RUS standard practices for conventional 12.4/24.9 kV AC distribution lines, which are used to develop AC interties throughout Alaska. With this approach, the resulting transmission structures modified for HVDC would require fewer conductors than AC, resulting in reduced loads on the supporting structures; conceptually this allows for longer transmission line spans and results in fewer transmission structures and associated construction costs.

5.1.2 Alaska-Specific Design Approach

The premise of the second scenario was to develop a new form of transmission infrastructure, assuming from the beginning that HVDC transmission would be used and focusing on reducing construction costs for rural Alaska interties. The following were the design considerations of Polarconsult in developing the resulting concepts:

1) Minimizing the reliance on heavy equipment that must be mobilized to a construction site
2) Maximizing the flexibility in construction methods and seasons
3) Using taller structures and longer spans
4) Using glass-fiber-reinforced polymer (GFRP) poles instead of wood or steel poles
5) Using guyed structures in areas where geotechnical conditions complicate the use of cantilevered poles directly buried in the soil, making cantilevered pole designs more costly

Comprehensive design and evaluation details of the resulting concepts can be found in Appendix C of [2].

In summary, a shared focus of these concepts is the use of a GFRP pole. This pole theoretically has several advantages when compared with traditional wood or steel poles, namely that it is lighter, can be sectioned and nested for easier field transport and assembly, and offers superior rot protection without the use of toxic preservatives. Another shared focus is the use of guyed poles, avoiding the need for steel piles and reducing base foundation size. A final shared concept is the use of innovative foundations specific to guyed poles in arctic conditions. The following are three foundation concepts developed by Polarconsult for application in a variety of geotechnical conditions found in Alaska:

1) Passively cooled thermoprobe micropiles
2) Small-diameter helical anchors
3) Smaller-diameter (4- to 6-inch) vertical piles

To test and demonstrate these concepts, Polarconsult conducted a field demonstration in December 2012. These concepts and demonstration are reviewed further in Section 5.3.

5.2 Economic Analysis of RUS Design Approach

The Alaska Center for Energy and Power (ACEP), in collaboration with the Institute of Social and Economic Research (ISER), has conducted an independent economic analysis comparing HVDC transmission designs proposed under Polarconsult's Scenario #1 (RUS Design Approach) with traditional AC transmission. This analysis highlights the major cost contributors (i.e., labor, substation, mobilization/demobilization costs, etc.) of a transmission line and illustrates how the transmission line costs vary depending on the type (AC, SWER, etc.) and length of the transmission line in normal and difficult terrain.

The cost of a transmission line, whether AC or DC, depends on many factors, including the distance between the power-generating location and the power-receiving location, construction factors such as the logistics of the site and the terrain where the line will be constructed, and weather conditions, all of which govern the design criteria for the system. Due to these factors, costs of transmission lines can vary significantly. This analysis performed the cost analyses using the RUS construction method, which also takes into account Alaska's extreme climate.

For this analysis, ACEP analyzed a proposed transmission project with theoretically "ideal" conditions (distance and power scale) for a small-scale HVDC project. Pilgrim Hot Springs, 60 road miles north of Nome, has been proposed as capable of supporting a 5 MW geothermal power plant. Developers would transmit the power to Nome via a newly constructed transmission line. This analysis estimates the cost of a 5 MW conventional overhead AC transmission line, an overhead HVDC monopolar two-wire system, and an overhead HVDC monopolar SWER transmission line to transport electricity from Pilgrim Hot Springs to Nome.

For these three scenarios, it is assumed that 21 of the 60 miles cross difficult terrain, adding additional costs to the project total.[5] Costs were developed on a per-mile basis and then adjusted based on the total intertie length to reflect economies of scale that would be realized due to the size of the project. Assumptions for the economies of scale from 0 to 25 miles are based on the cost analysis done by Polarconsult. [6] Per mile pre-construction cost for the intertie is assumed to decrease by 36% when the intertie length increases from 10 to 25 miles, another 5% from 25 to 50 miles, and an additional 5% from 50 to 60 miles. Per mile shipping and mobilization/demobilization cost is assumed to decrease by 8% when the intertie length increases from 10 to 25 miles, 5% from 25 to 50 miles, and an additional 5% from 50 to 60 miles. Per mile administration/management cost, material cost, and labor cost are assumed constant. All the cost estimates are in 2012 dollars.

Notably, this analysis did not estimate the costs for an HVDC bipolar transmission line, because a bipolar transmission line is more costly with its two additional converter stations (one on each pole) than a monopolar HVDC line is. The HVDC bipolar system would use four converters instead of two (monopolar). For a fixed intertie capacity, each converter on a bipolar system is half the capacity of a converter on a monopolar system. However, the increased station complexity for a bipolar system still results in relatively higher costs than for a monopolar system. Bipolar transmission lines offer increased reliability. If one of the lines fails to operate, the other can still perform as a monopolar line. Nome's population as of 2011 is under 4000 (according to the State of Alaska's Department of Labor and Workforce Development), and the Nome Joint Utility System (NJUS) currently uses a diesel generator supplemented with a small amount of locally generated wind power to produce electricity. Rather than spending considerable additional money on converters and wires for a bipolar system, Nome can use its existing diesel generation system for backup in case of line failure. For this reason, there is a reduced need for the higher cost of a bipolar system.

5.2.1 Overhead AC Intertie

The first cost estimation is for a 60-mile 69 kV AC three-wire overhead intertie on wood poles (35 to 45 feet tall) spaced at 14 poles per mile, which totals 840 poles from Pilgrim Hot Springs to Nome). The estimated cost for the intertie itself is $23.3 million. Accounting for the difficult terrain, which adds approximately $1.6 million to the total cost, the intertie cost becomes $24.9 million. Table 2 shows the cost summary for the total intertie system. The substation cost is $3 million, pre-construction cost is about $5.6 million, administrative and management cost is about $2.4 million, and contingency cost is about $6.5 million. The total project cost to build the intertie with substations is estimated to be approximately $39 million (The assumptions behind these numbers are mentioned in Section 5.2. See Appendix 8.1 for more details).

Intertie and Substation Costs	
Pre-construction	$5,604,000
Administration/Management	$2,380,000
Materials	$4,260,000
Shipping	$1,903,000
Mobilization/Demobilization	$7,198,000
Labor	$6,660,000
Additional Cost due to Difficult Terrain	$1,631,000
Construction of Substations (both sides of the line)	$3,000,000
Contingency	$6,527,000
TOTAL	**$39,163,000**

Table 2: Intertie and Substation Costs for the Overhead AC Intertie

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[5] "Difficult terrain," means mountainous. It costs more to put poles on hilly, rocky land than on flat land. It is assumed that costs to construct an intertie in difficult terrain will cost 20% more than construction in normal terrain.

[6] Polarconsult has done a hypothetical 25-mile 24.9 kV AC transmission line, but our analysis is for a 60-mile 69-kV AC transmission line.

In addition to the above estimation, costs of historical and comparable projects in Alaska were explored. The table below shows estimated cost data from five intertie projects in western Alaska.[7] As the cost data show, intertie cost can vary significantly depending on location, length of the intertie, terrain, and other factors. The historical data do not describe whether the estimated costs include preconstruction, administration, shipping, substation, and other costs. If we take these unknown variables into consideration, then the cost could be considerably higher or lower than that presented in the table. We calculated the average estimated cost of the Nome–Pilgrim intertie, based on the historic cost data in Table 3, to be around $22 million. [8]

Intertie	Approximate Length (Miles)	Estimated Cost per Mile (2012 $)[9]	Year Built
Emmonak–Alakanuk	11	$407,000	2011
Toksook Bay–Tununak	6.6	$352,000	2006
New Stuyahok–Ekwok	8	$387,000	2007
Nightmute–Toksook Bay	18.04	$408,000	2009
Bethel–Napakiak	10.5	$313,000	2010
Average Estimated Cost per Mile		**$373,000**	
Estimated Cost for 60-mile Intertie		**$22,404,000**	

Table 3: Overhead AC Intertie Estimated Costs from Historical Data from Previous Projects [42]–[46]

Table 4 presents the cost range for the intertie in terms of the total cost and the per mile cost. The estimated total cost for the intertie from Pilgrim Hot Springs to Nome may vary from $22 million to $39 million, and the estimated per mile cost may vary from $373,000 to $653,000.[10]

Intertie Cost Range	
Intertie and Substation Cost (Low Estimate)	$22,404,000
Intertie and Substation Cost (High Estimate)	$39,164,000
Intertie and Substation Cost per Mile (Low Estimate)	$373,000
Intertie and Substation Cost per Mile (High Estimate)	$653,000

Table 4: AC Intertie Estimated Cost Range

5.2.2 Overhead HVDC Interties

The next estimation is for two HVDC intertie scenarios: HVDC monopolar 2-wire intertie and HVDC monopolar SWER intertie. Both systems assumed a 60-mile 50 kV overhead intertie on wood poles (50 to 60 feet tall), spaced at 6 poles per mile (which totals 360 poles from Pilgrim Hot Springs to Nome) with standard RUS construction methods.

HVDC Monopolar 2-Wire Intertie

The estimated cost for the HVDC 2-wire (including return conductor) intertie itself is $17.2 million. Accounting for difficult terrain, which adds $1.2 million to the total cost, the intertie cost becomes $18.4 million. Table 5 shows the cost summary for the total intertie system (see Appendix 8.2 for more details). Given that the intertie needs converter stations on each side of the transmission line to convert the electricity from AC to DC and DC to AC, and assuming that the contingency cost is 20% of the project cost, the intertie cost may range from approximately $30

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[7] These interties are chosen for the analysis because they are located in western Alaska and may represent similar weather and terrain conditions as the Nome to Pilgrim Hot Spring intertie.

[8] These costs are based on 14.4/24.9 kV AC interties, but the hypothetical Nome-Pilgrim Intertie is a 69 kV intertie, which might have a little higher cost due to increased ground clearance, increased conductor clearance, different insulators, etc.

[9] The dollar values have been adjusted to 2012 dollars using national CPI data.[57]

[10] Higher estimate is almost $653,000 per mile, since the total cost for the 60-mile transmission line is around $39,163,000.

million to $33 million. The converter station cost varies from $2.1 million to $4.8 million depending on cost assumptions used. Polarconsult has two possible assumptions for the converter costs: (a) $1.04 million for each MW converter station or approximately $2 million for this intertie, and (b) $250,000 ± 10% per 1 MW power converter or approximately $3.4 million to $4.8 million for this intertie.[11] The Electric Power Research Institute (EPRI) assumes a converter station cost of around 15% of the total cost or approximately $3.4 million for this intertie. [47]

COST CATEGORY	EPRI	$250,000 - 10% per 1 MW Converter	$250,000 + 10% per 1 MW Converter	$1.04 million for each Converter
Pre-construction	$5,928,000	$5,928,000	$5,928,000	$5,928,000
Administration/Management	$2,020,000	$2,020,000	$2,020,000	$2,020,000
Materials	$2,820,000	$2,820,000	$2,820,000	$2,820,000
Shipping	$1,374,000	$1,374,000	$1,374,000	$1,374,000
Mobilization/Demobilization	$5,165,000	$5,165,000	$5,165,000	$5,165,000
Labor	$4,260,000	$4,260,000	$4,260,000	$4,260,000
Additional Cost due to Difficult Terrain	$1,202,000	$1,202,000	$1,202,000	$1,202,000
Converter Station Construction[12]	$3,415,000	$3,413,000	$4,813,000	$2,080,000
Contingency (20%)	$5,237,000	$5,236,000	$5,516,000	$4,970,000
TOTAL	**$31,421,000**	**$31,419,000**	**$33,099,000**	**$29,819,000**

Table 5: HVDC Monopolar 2-Wire Intertie Estimated Cost with Difficult Terrain and Different Converter Station Cost Assumptions

Table 6 presents the cost range for the HVDC monopolar intertie in terms of the total cost and the per mile cost. The estimated total cost for the intertie from Pilgrim Hot Springs to Nome may vary from $30 million to $33 million, and the estimated per mile cost may vary from $497,000 to $552,000.

HVDC Monopolar Two-Wire Intertie Estimated Cost Range	
Intertie and Converter Station Cost (Low Estimate)	$29,819,000
Intertie and Converter Station Cost (High Estimate)	$33,098,000
Intertie and Converter Station Cost per Mile (Low Estimate)	$497,000
Intertie and Converter Station Cost per Mile (High Estimate)	$552,000

Table 6: HVDC Monopolar 2-Wire Intertie Estimated Cost Range

HVDC Monopolar SWER Intertie

The estimated cost for the monopolar SWER intertie is $13.2 million. Accounting for the difficult terrain, which adds $0.92 million to the total, the intertie cost becomes $14.12 million. Table 7 shows the cost summary for the total intertie system (see Appendix 8.3 for more details). Given that the intertie needs converter stations on each end of the transmission line to convert the electricity from AC to DC and DC to AC, and assuming that the contingency cost is 20% of the project cost, the estimated cost for the intertie ranges from $23.6 million to almost $28 million, with the converter stations cost estimate varying from $1.2 million to $4.8 million. Polarconsult Alaska

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[11] $250,000 ± 10% per 1 MW power converter: Does not include the switchyard, enclosure, grounding system, and other elements that comprise a complete converter station.

[12] The other variables in the cost category (e.g., pre-construction, administration/management, materials, shipping, mobilization/demobilization, labor, and additional cost due to difficult terrain) use the same assumptions for all four total cost assumption (e.g., EPRI, $250,000 – 10% per 1 MW Converter, $250,000 + 10% per 1 MW Converter, and $1.04 million for each converter); so in the table, converter station construction cost and contingency have different values for those total cost calculations and the rest of the values for the cost category remains the same across different total cost calculations.

has two estimates for the converter costs: (a) $1.04 million per converter, and (b) $250,000 ± 10% per 1 MW converter.[13] EPRI assumes the converter station cost is around 15% of the total. [47]

COST CATEGORY	EPRI	$250,000 - 10% per 1 MW converter	$250,000 + 10% per 1 MW converter	$1.04 million for each converter
Pre-construction	$6,019,000	$6,019,000	$6,019,000	$6,019,000
Administration/Management	$1,780,000	$1,780,000	$1,780,000	$1,780,000
Materials	$2,880,000	$2,880,000	$2,880,000	$2,880,000
Shipping	$824,000	$824,000	$824,000	$824,000
Mobilization/Demobilization	$2,033,000	$2,033,000	$2,033,000	$2,033,000
Labor	$4,020,000	$4,020,000	$4,020,000	$4,020,000
Additional Cost due to Difficult Terrain	$921,000	$921,000	$921,000	$921,000
Converter Station Construction	$2,772,000	$3,413,000	$4,813,000	$2,080,000
Contingency (20%)	$4,250,000	$4,378,000	$4,658,000	$4,111,000
TOTAL	**$25,499,000**	**$26,268,000**	**$27,948,000**	**$24,668,000**

Table 7: HVDC Monopolar SWER Intertie Estimated Costs with Difficult Terrain and Different Converter Station Cost Assumptions

Table 8 presents the cost range of the total cost and the per mile cost estimates for the intertie. The estimated total cost for the intertie from Pilgrim Hot Springs to Nome varies from $25 million to $28 million, and the estimated per mile cost varies from $411,000 to $466,000.

HVDC Monopolar SWER Intertie Estimated Cost Range	
Intertie and Converter Station Cost (Low Estimate)	$24,668,000
Intertie and Converter Station Cost (High Estimate)	$27,948,000
Intertie and Converter Station Cost per Mile (Low Estimate)	$411,000
Intertie and Converter Station Cost per Mile (High Estimate)	$466,000

Table 8: HVDC Monopolar SWER Intertie Estimated Cost Range

5.2.3 Summary of Intertie Estimated Costs with Different Technologies

Table 9 presents the summary calculated intertie costs for the three scenarios, per the above estimations.

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[13] $250,000 ± 10% per 1 MW power converter: Does not include the switchyard, enclosure, grounding system, and other elements that comprise a complete converter station

Intertie Estimated Cost with Different Technologies			
Type of Intertie	**Cost Calculation Method**	**Total Cost**	**Per Mile Cost**
AC Intertie Cost	Using Unit Cost	$39,164,000	$653,000
	Using Historical Prices($/mile)	$22,404,000	$373,000
HVDC Monopolar Two-wire	EPRI	$31,421,000	$524,000
	$25,000-10% (converter station cost)[14]	$31,419,000	$524,000
	$25,000+10% (converter station cost)	$33,099,000	$552,000
	$1.04 million for each converter	$29,819,000	$497,000
HVDC Monopolar SWER	EPRI	$25,499,000	$425,000
	$25,000-10% (converter station cost)	$26,268,000	$438,000
	$25,000+10% (converter station cost)	$27,948,000	$466,000
	$1.04 million for each converter	$24,668,000	$411,000

Table 9: Intertie Estimated Cost with Different Technologies

Table 10 lists the estimated range of intertie costs in terms of total cost and per mile cost.

Intertie Cost Range		
Type of Intertie	**Total Cost**	**Per Mile Cost**
AC Cost – Low Estimate	$22,404,000	$373,000
AC Cost – High Estimate	$39,164,000	$653,000
HVDC Monopolar 2-wire Cost – Low Estimate	$29,819,000	$497,000
HVDC Monopolar 2-wire Cost – High Estimate	$33,098,000	$552,000
HVDC SWER Cost –Low Estimate	$24,668,000	$411,000
HVDC SWER Cost –High Estimate	$27,948,000	$466,000

Table 10: Intertie Estimated Cost Range

5.2.4 Life-Cycle Cost Comparison of the Interties

Table 11 shows the life-cycle cost comparison for low, medium, and high intertie cost estimates of the three scenarios. The life-cycle cost analysis shows that the HVDC 2-wire monopolar system is 130% of the cost of an AC intertie system, and the HVDC monopolar SWER system is 111% of the cost of an AC intertie system when the low cost estimation for the intertie cost analysis is used. These numbers change with use of the medium and high cost estimations. Using the medium cost estimation, the HVDC 2-wire monopolar system is 105% of the AC intertie system, and the HVDC monopolar SWER system is 91% of the AC intertie system. With the high cost estimation, the HVDC 2-wire monopolar system is 90% of the AC intertie system, and the HVDC monopolar SWER system is 78% of the AC intertie system.

Due to lack of economic data for small-scale HVDC intertie systems, some assumptions that Polarconsult Alaska used for their analysis are used in this analysis. Despite the use of some of the same assumptions, the results of our economic analyses differ somewhat from those of Polarconsult. Polarconsult's estimations show that the HVDC 2-wire monopolar system is 107% of the AC intertie system and that the HVDC monopolar SWER system is 79% of the AC intertie system. Polarconsult's life-cycle cost estimation is for a 25-mile overhead intertie, and our analysis is for a 60-mile overhead intertie. Also, Polarconsult's cost estimations for the 60-mile overhead intertie shows somewhat different results from our cost estimates for the 60-mile overhead intertie. According to the Polarconsult analysis, the 60-mile overhead AC intertie from Pilgrim Hot Springs to Nome costs approximately $36 million. However, according to our analysis, the cost is $22 million with low cost assumptions, $30 million with medium cost assumptions, and $39 million with high cost assumptions.

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[14] Polarconsult Alaska has two possible assumptions for the converter costs: (a) $580,000 per converter, and (b) $250,000 ± 10% per 1 MW converter.[2]

Estimated Life-Cycle Cost Analysis for the Interties

Parameter	AC Intertie	HVDC 2-Wire Monopolar	HVDC Monopolar SWER
Converter Efficiency (for both converters)	98%	96%	96%
Transmission Line Loss	3%	1%	0.5%
Annual Transmission Losses in Converters and Transmission Lines (kWh)	2,422,000	2,739,000	2,588,000
Annual Value of Transmission Losses[15]	$391,000	$443,000	$418,000
Intertie Annual O&M Cost	$96,000	$139,000	$130,000
Project Life (years)[16]	20	20	20
Discount Rate	3%	3%	3%
Present Value of Transmission Loss	$5,823,000	$6,585,000	$6,222,000
Present Value of O&M	$1,428,000	$2,071,000	$1,928,000
Intertie + Converter Station Cost (low value)	$22,404,000	$29,819,000	$24,668,000
Intertie + Converter Station Cost (medium value)	$30,784,000	$31,459,000	$26,308,000
Intertie + Converter Station Cost (high value)	$39,164,000	$33,098,000	$27,947,000

Intertie + Converter Station Cost (low cost)

	AC Intertie	HVDC 2-Wire Monopolar	HVDC Monopolar SWER
Estimated Life-Cycle Cost	$29,655,000	$38,475,000	$32,818,000
HVDC Life-Cycle Cost as Percentage of AC Life-Cycle Cost		130%	111%
Present Value of Savings (Cost) for HVDC Compare to AC		($8,820,000)	($3,163,000)

Intertie + Converter Station Cost (medium cost)

	AC Intertie	HVDC 2-Wire Monopolar	HVDC Monopolar SWER
Estimated Life-Cycle Cost	$38,035,000	$40,115,000	$34,458,000
HVDC Life-Cycle Cost as Percentage of AC Life-Cycle Cost		105%	91%
Present Value of Savings (Cost) for HVDC Compare to AC		($2,080,000)	$3,577,000

Intertie + Converter Station Cost (high cost)

	AC Intertie	HVDC 2-Wire Monopolar	HVDC Monopolar SWER
Estimated Life-Cycle Cost	$46,415,000	$41,754,000	$36,097,000
HVDC Life-Cycle Cost as Percentage of AC Life-Cycle Cost		90%	78%
Present Value of Savings (Cost) for HVDC Compare to AC		$4,661,000	$10,319,000

Table 11: Estimated Life-Cycle Cost for the Interties

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[15] Electricity price is assumed to be $0.1616 per kWh throughout the line.

[16] The life of the intertie is assumed to be 20 years, since the intertie will be used to transmit energy from a geothermal project which has a lifetime of 20 years as well. Even if we change the life of the intertie to 50 years, the "HVDC Life-Cycle Cost as a Percentage of AC Life-Cycle Cost" does not change much.

5.2.5 Comparative Findings

These cost estimations assume an economy of scale so that the total construction cost increases at a decreasing rate for a longer intertie. Pre-construction, shipping, mobilization/demobilization, operation and maintenance (O&M), and labor costs are project-specific and mainly depend on the distance between the power-generating and power-receiving locations, the terrain, and weather conditions. Another major cost category is the converter station or substation cost. Minimal data are available on the cost of a substation for a small-scale (5 MW or less) project. Life-cycle cost analysis shows that HVDC is a better option for a 60-mile intertie if one assumes the high or medium cost estimation. For low-cost estimation, an AC intertie is a better option. The economic analyses in this report are based on assumed data from different sources. More empirical data for small-scale HVDC intertie are needed for a more rigorous economic analysis.

5.3 Demonstration of Alaska-Specific Design Approach

To review the resulting conceptual designs and evaluations of the Alaska-specific design approach, Polarconsult conducted a field demonstration of select conceptual system components. Objectives included demonstration of installation and performance of the following:

1) Glass Fiber-Reinforced Plastic (GFRP) pole
2) Micro-thermopile pole foundations
3) Micro-thermopile guy anchors
4) Screw guy anchors
5) Overall guyed GFRP pole structure

This demonstration was conducted on private property in Fairbanks near the University of Alaska Fairbanks. The site was selected primarily for ease of access and localized conditions representative of "… the most common geotechnical conditions that pose the greatest technical and economic challenges for rural Alaska overhead intertie lines as currently designed." For comprehensive information on the demonstration, see Appendix C.6 of [2]. The following is a review of the demonstration, conducted by ACEP staff from site visits, and a review of Polarconsult's conceptual design and evaluation documents and reporting.

5.3.1 Overview of Demonstration Activities

Polarconsult assembled and erected a 60-foot GFRP pole, made up of a 40-foot section and a 20-foot section, demonstrating assembly time and effort required. The GFRP was erected using a line truck on a micro-thermopile tripod foundation with a hinge assembly to raise of lower the pole in situations where cranes, booms or heavy equipment was not available. The GFRP was secured using four 3/8-inch guy lines set at 90 degrees to each other and 45 degrees to the ground. Each guy had a unique anchoring method, including the use of two micro-thermopiles (one in-line with the guy, and one vertically offset by 25 degrees), a screw anchor, and a swamp anchor. All thermopiles were installed using a GeoProbe 8040 series drill rig (the line truck installed the screw and swamp anchors).

The following are photos of the installed GFRP pole:

Figure 8: GFRP Pole as Installed

The following are photos of the pole foundation (left) and one of the guy-wire anchors (right):

Figure 9: GFRP Pole Foundation (left) and Guy-Wire Anchor (right)

5.3.2 Review of Demonstration

Overall, the demonstration was successful in providing a relevant Alaska field application of conceptual system components developed through this project. A functional GFRP pole, anchors, and various foundation systems were manufactured using commercially available products and services, and were deployed without complication while meeting the design expectation. In particular, the pole was delivered in two sections, assembled, and erected in the course of an uneventful day.

There are several concerns identified by ACEP staff as a result of the demonstration. These concerns are as follows:

1) Lack of long-term monitoring.

   Due to unanticipated delays in securing a site and finalizing an access and land-use agreement, the demonstration did not begin until November 2011, one month prior to the planned closure of project activities. As such, no long-term data are available from the demonstration. This data deficiency limits the ability to assess the performance of the system or its components. Key performance questions outstanding because of this data deficiency include long-term performance of the GFRP pole, impact of the anchors and foundation on the localized thermal profiles, tension of the guy wires over time, and presence/impact of vertical shifting of anchors and the foundation. It is important to note that the system is equipped to monitor these key performance aspects; Polarconsult plans to monitor the system outside of project activities. Such information should be expected as a voluntary addendum to Phase II reporting, ideally gathered over the course of two or more years of thermal cycles.

2) Deployment of a single pole.

   The demonstration included the deployment of a single pole without the loads and stresses one would expect with a pole that supports a transmission line. This deficiency reduces the value of any anticipated long-term performance data; pole, foundation, and anchor performance, for instance, is not within the context of anticipated normal operating conditions of the system, including wind and ice effects on a pole loaded with a transmission line.

3) Lack of isolated variables.

   The demonstration implemented many innovations in one system; the anchors in particular were not standardized. While these innovation implementations do not invalidate the anticipated performance data from the system, they cast doubt on findings dealing with the potential interaction of dissimilar system components performing the same intended function.

4) Undemonstrated functionality.

   Several designed aspects of the system were not demonstrated. For instance, the demonstration relied on the use of equipment (e.g., a line truck) that would not necessarily be available in all locations of intended deployment; and the hinge on the micro-thermopile tripod, designed for use during remote field erection, was not demonstrated. In addition, and perhaps more importantly, the demonstration did not include an investigation of maintenance methods. This is of particular concern given the use of a GFRP pole, often stated as a primary concern of utilities and operators, and noted by the SAG [48]. Concerns about scaling a fiberglass pole in remote and harsh conditions, for example, are a significant barrier to industry adoption and one that demands further field testing and verification.

The high cost of construction of transmission lines in remote or rural Alaska locations remains a deterrent to creating more efficient and effective energy infrastructure, limiting the ability to intertie communities, access stranded energy resources, and capitalize on economies of scale. This activity has successfully demonstrated a potentially viable alternative approach to developing power transmission in Alaska, designing “up” from location and construction cost requirements, and not just modifying current industry practice.

In terms of next steps, it is recommended that further development of an Alaska-specific design approach to power transmission be conducted as a separate activity from the development of small-scale HVDC converters. There remains considerable work in development and demonstration for this approach as a technology to be commercially ready, and significant safety, reliability, and financial risks to it being adopted by an Alaska utility or operator. Polarconsult should be commended for the extent of effort it put into this activity, and the progress it achieved through this project. This technology, however, is merely complementary to small-scale HVDC transmission, already a pre-commercial technology with significant hurdles in development and demonstration to overcome.

It is critical that an interested party (e.g., an Alaska utility, operator, or key stakeholder) and application specific to this technology, separate from small-scale HVDC transmission, is identified before further development takes place. Without substantial “buy-in” or involvement with potential utilities or operators, progress toward a commercial product will be difficult. Per the needs and interests of the identified party and application, a revised demonstration should take place that includes a more representative system, a reduction of variables, long-term performance monitoring, and demonstrated functionality of field deployment, maintenance, and operation.

5.4 Review of the Feasibility of SWER in Alaska

A concept that is featured in the Polarconsult feasibility design and demonstration is the incorporation of SWER into small-scale HVDC transmission configurations. As discussed in Section 3.3, SWER was brought into consideration by Polarconsult because, while HVDC alone can potentially be a means for lowering electricity costs in rural Alaska, HVDC in conjunction with SWER can reduce costs even further. Capital costs for installation of a SWER line can be as low as half the cost of an equivalent 2-wire single-phase line [23]. Moreover, rural Alaska has a population and energy structure that lends itself well to SWER—a low-density, widely scattered population, and very little infrastructure in areas in between population centers.

In the late 1970s, two SWER demonstration projects were funded by the Alaska Energy Center (an organization that existed for four years in the early 1980s) through the Alaska State Legislature to test the concept's applicability to rural Alaska. One line was constructed from Bethel to Napakiak; the other line was constructed to connect Kobuk to Shungnak.[49] Details are described in the following two sections, 5.4.1 and 5.4.2.

5.4.1 Bethel–Napakiak AC SWER Line

In 1980, an 8.5-mile (14 km)-long, 14.4 kV AC intertie using SWER was built between Bethel and Napakiak, allowing the Napakiak Ircinraq Power Company to purchase power from the Bethel Utilities Corporation. The line was intended specifically to be a demonstration of feasibility of SWER in rural Alaska, and was built by RW Rutherford and Associates using simplified construction methods that relied mostly on snow machines and hand tools. The construction cost was $23,000 per mile in 1980 dollars (approximately $69,000 in 2013 dollars) [50], and it operated successfully until increasing loads from Bethel to Napakiak exceeded the capacity of the line to deliver reliable power, leading to frequent blackouts. Furthermore, the poles, which were an experimental design, gradually deteriorated until they experienced mechanical failures and physically collapsed.

There were also some problems with lack of proper grounding and assurance of continued grounding. Some of the fault trips failed, and faults did not trip fusing or relaying, allowing over-voltages and unsafe conditions.

In 2009, the deteriorating line was fully replaced with traditional pile foundation-supported poles and conventional 3-phase AC, at the cost of $3.13 million [51]. Figure 10 shows the new line under construction beside the old SWER line.

Figure 10: Failed Pole Support Due to Lack of Grounding and Lack of Fault Detection (left, source: Alaska Industrial Development and Export Authority). New Bethel–Napakiak 3-Phase AC Intertie Under Construction (right, source: Denali Commission).

5.4.2 Kobuk–Shungnak AC SWER Line

In 1980, a 10.5-mile (17 km)-long SWER line was also built between Kobuk and Shungnak by Anchorage-based engineer Thomas D. Humphrey. Like the Bethel–Napakiak intertie, the line was built using local labor and simple tools and was intended to demonstrate the feasibility of SWER in a rural setting, but it was even more experimental in nature, with costs further reduced by using local materials and local labor to construct the power line. Additionally, the route was along continuous permafrost, requiring some variations in the A-frame pole structure. Safety concerns were addressed by erecting barbed wire around the line, ensuring that no one would walk along the ground return path. Additional details are as follows:

> *The Kobuk system design included two important factors lacking in the Bethel-Napakiak system:*
>
> 1. *Two wires instead of one were used; the two wires ensured that the City of Kobuk would be serviced with electricity even if the ground return portion of the line failed. Applications of a SWGR concept in the continuous permafrost were uncertain.*
> 2. *Intermediate [in location] customers will be able to tie into the transmission line in Kobuk, which is not true of the Napakiak line.*
>
> *The A-frame structure was modified to an X-shape to allow a simple balanced configuration for the second wire while maintaining the required flexibility of the structure. This X-frame is not recommended in future transmission systems in rural Alaska. During a 90 mph+ high wind, a section of X-frames toppled. The support at the intersection weakened the integrity of the pole enough to cause several to break upon impact with the ground. [49]*

In 1991, the deteriorating line was replaced with a conventional AC line at the cost of $1,350,000 [51].

5.4.3 Proposed SWER Systems

Single-wire earth return systems have been sporadically proposed for various transmission projects in Alaska. The following are examples of such proposals.

- Chikuminuk Lake (Bethel area), proposed hydroelectric project

  The Nuvista Light & Electric Cooperative has proposed, under the proposal Chikuminuk Lake Hydroelectric Project, to use a dam and penstock system to generate power from Chikuminuk Lake, and distribute the power to the Bethel region, including the communities of Akiachak, Akiak, Kwethluk, Tuluksak, Oscarville, Napakiak, Napaskiak, Atmautluak, Kasigluk, Nunapitchuk, Tuntutuliak, Eek, and Quinhagak. “Nuvista requested and was approved for $17.6 million in funding from the Alaska State Legislature in 2011, but was later reduced to $10 million by Governor Sean Parnell. This funding is to cover the project’s second phase of federal permitting, initial design, feasibility studies and public meetings." [52]

The current proposal calls for using HVDC interties, and at least one proposal on the table calls for SWER. This would be a test not only of SWER in Alaska but of a multi-nodal HVDC network. Figure 11 shows the proposed intertie system.

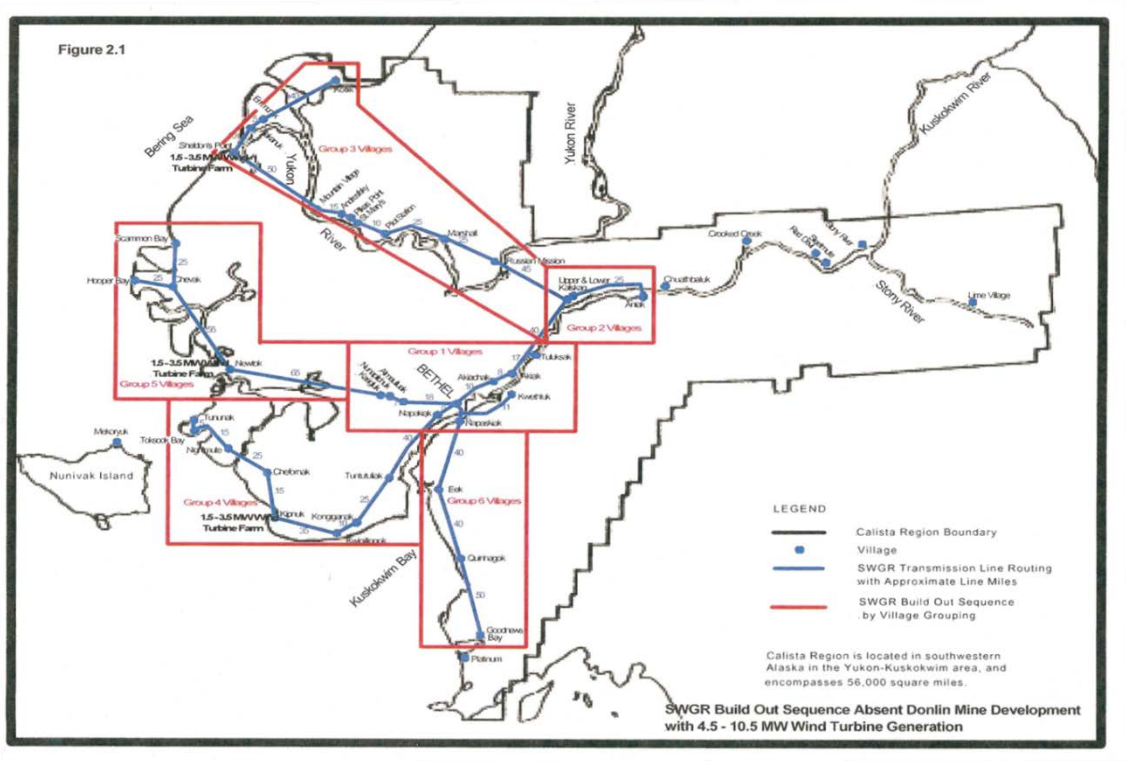

Figure 11: Proposed SWER Intertie System from Chikuminuk Lake (source: [52])

- Nushagak Area Hydroelectric Project (Dillingham area)

Grant Lake is the current favored site (as of 2009) [53] of a hydroelectric project to provide power to Dillingham and the surrounding communities. In 1980, SWER was considered for transmission of hydroelectric power to Dillingham (at the time, Lake Elva was considered the optimal location, size, and setting for a hydropower project) [54]. Today, SWER is no longer under consideration, but as Grant Lake is about 60 miles (100 km) from the local population hub of Dillingham, HVDC could be economical there.

5.4.4 Potential for SWER Application in Alaska

The two SWER projects in Alaska to date have demonstrated SWER as a technically feasible, low-cost method of transmission, although serious questions around conductance in frozen soils, fault and safety strategies, reliability, system longevity, and pole design and construction remain. In addition to these questions, the regulations surrounding the use of SWER highlight the challenges of using this technology in Alaska.

In the United States, the National Electrical Safety Code (NESC), which is established by the Institute of Electrical and Electronics Engineers (IEEE), addresses the usage of SWER. The NESC does not currently allow SWER on a system-wide basis, except in emergency situations and as a backup to the traditional line in case of failure.

However, communication between the Alaska Department of Labor, which enforces the NESC code in Alaska, and ACEP have suggested that SWER systems may be allowable by project-specific waiver on a case-by-case basis, as the two demonstration projects in the 1980s were allowed. Site-specific engineering was recommended to assure compliance and public safety. [55]

One of the factors that make the situation in Alaska unique is that the interties would traverse undeveloped regions of very low population density. Therefore, the risk to human safety, and the risk of increased corrosion to buried underground structures, is far lower than in almost any other region in the world.

For rural electrification in Alaska, it seems reasonable to suggest that SWER be used in applicable situations with a time-limited code waiver. To be a good candidate for an intertie, after 10 years (which is a typical duration), the electricity used by a region would need to have increased enough to financially support either a conventional 3-phase AC or a bipolar HVDC system. This is what happened with both the Bethel–Napakiak and the Kobuk–Shungnak lines.

In 2011, at the commissioning of the Electrical Inspection Department of the State of Alaska, the Manitoba HVDC Research Centre published a report on the potential to use SWER in Alaska. The report states that it also aimed to address questions from Polarconsult. The report outlook is cautiously optimistic; among the conclusions were the two statements:

1) *It is recognized that Single Wire Earth Return (SWER) whether it is AC or DC can provide a low cost method of transmitting grid power to remote locations with small loads.*
2) *SWER projects have been installed safely throughout the world [56].*

On the other hand, SWER has not been in extensive use in permafrost regions. Ice is a semiconductor; thus frozen soils have far lower electrical conductivity than water-rich soils at temperatures above freezing. The Kobuk–Shungnak demonstration, for example, addressed concerns about conductivity in frozen soils by building the line along a river, intending that the return path would be within the river's thaw bulb. Aside from electrical concerns, the mechanics of placing poles into ice-rich ground pose challenges that are unique to circumpolar regions, such as frost jacking and frost heaving.

Once the challenges of permafrost are met, the dynamic effects of a rapidly changing global climate must be considered. Presently, permafrost is melting in circumpolar regions. While this improves soil conductivity, it also reduces soil mechanical strength, so structural support will be worse. Freeze-thaw cycles are shifting from what they were in the past, and freeze fronts in the active layer are no longer penetrating to the permafrost every winter. Some locations in winter now have frozen ground over an unfrozen layer over permafrost. While a potential upside to this is that the unfrozen ground layer may provide an improved return current pathway for a SWER system, the unknown effects of such dynamic conditions with high rates of change present a design challenge with an unusually high degree of uncertainty. Designs can likely address these challenges, but not without potentially significant cost implications for future projects.

Another barrier to SWER that is unique to regions in Alaska is that many areas in the state, for example, the region around Unalakleet, have lava beds as their soil foundations. Like permafrost, lava beds provide better structural support, but poorer electrical conductivity, than typical soils found worldwide.

Despite these challenges, SWER remains an intriguing possibility for particular transmission projects in Alaska, whether AC or DC, given supporting Alaska conditions such as a low-density, widely scattered population, and very little infrastructure in areas in between population centers, and widespread global application. However, in terms of HVDC transmission and this project, SWER is merely complementary; future investigation should be conducted as a separate activity and only with significant "buy-in" and involvement from key stakeholders. The AKDoL has indicated openness to reviewing the regulations regarding the use of SWER in Alaska. Presumably, this could provide an opportunity to formally investigate the various outstanding technical questions regarding the use of SWER in Alaska conditions.

6.0 Summary of Findings and Recommendations

The Polarconsult Small-Scale HVDC project seeks to design, develop, and demonstrate (1) small-scale HVDC converters and (2) innovative complementary transmission infrastructure to reduce the cost of power delivery for rural Alaskans. Phase II of the project included design, fabrication, and testing of fully functional prototypes of the converter system and transmission system elements. The following are the summary of findings and recommendations for Phase II as reviewed in this report.

6.1 Development and Demonstration of PPS Converters

The project demonstrated the technical feasibility of the converter; however, several critical hardware issues need to be addressed before further demonstration can take place. The converter was tested in rectifier mode with the HV tank in open air at lower voltage and filled with Luminol oil at full voltage. The converter was demonstrated to function in rectifier mode producing 50 kV DC from 3-phase 480 VAC, but under low power conditions due to limited loading capability at the PPS lab. The converter was also tested in inverter mode at very low power conditions (essentially no load) to demonstrate the voltage and current control concepts discussed in Section 4.1. Testing of the inverter mode of operation was limited due to hardware issues including current leakages, the loss in the optical triggering system for the IGBT switches, which caused timing issues, and the thermal runaway of the IGBTs. The functionality of the LVAC/LVDC bridge has not been verified in this specific converter.

Once a fully functional prototype is developed, independent testing of the converters will still be needed to validate efficiency and performance, followed by deployment on an Alaska utility system to validate functionality and reliability in a commercial setting. Nontechnical challenges also exist to deployment in Alaska. Aside from technical problems that may arise with HVDC and SWER systems, there are problems related to a lack of labor and appropriate human capital in remote Alaska regions for maintaining and operating equipment, whether for regular proactive maintenance or for unforeseen repairs.

It is recommended that before further project activities commence, design and performance standards for the envisioned converter technology be formally codified by a professional stakeholder group like the SAG. Such standards could include target operating conditions, operations and maintenance requirements, integration and controls functionality, and even materials characterization. Standards codified in this manner would incorporate lessons learned from the project to date, increase stakeholder “buy-in” and involvement, and focus technology development efforts.

It is further recommended that future project funding for converter development be conducted under a competitive solicitation, like a Request for Proposal (RFP) process, using the developed standards as product specification. This process would neither preclude PPS from further project involvement, nor negate the work that has gone into developing the current converters, but would allow other technology developers an opportunity to compete for funding and provide well-understood specifications for a final product being delivered to Alaska for testing.

There are many technically feasible approaches to the envisioned final small-scale product, just as in medium-scale HVDC technology. Much has been learned about this technology since 2008, and industry interest in small-scale HVDC has increased since the conception of this project. In addition, as noted in Section 3.1.4, there are other industries with relevant technologies and recent advancements that could feasibly be converted to this application. The adaptation of a converter from another industry might be a faster and more inexpensive route to small-scale power conversion than development of a new power converter from the ground up, especially as different industries may interact in ways that are fortuitously beneficial toward combining technology.

6.2 Development and Demonstration of Alaska-Specific Design Approach

Polarconsult conducted a field demonstration of a system composed of a GFRP pole, micro-thermopile pole foundations, micro-thermopile guy anchors, and screw guy anchors. Overall, the demonstration was successful in providing a relevant Alaska field application of conceptual system components developed through this project. A functional GFRP pole, anchors, and various foundation systems were manufactured using commercially available products and services, and were deployed without complication while meeting the design expectation. In particular, the pole was delivered in two sections, assembled, and erected in the course of an uneventful day. Several concerns have been identified by ACEP staff as a result of the demonstration, including the lack of long-term monitoring, the deployment of a system composed of a single pole, the lack of isolated variables in the demonstration, and undemonstrated functionality such as system maintenance and remote deployment methodologies.

The high cost of construction of transmission lines in remote or rural Alaska locations remains a significant barrier to creating more efficient and effective energy infrastructure, limiting the ability to intertie communities, access stranded energy resources, and capitalize on economies of scale. This activity has successfully demonstrated a potentially viable alternative approach to developing power transmission in Alaska, designing “up” from location and construction cost requirements, and not just modifying current industry practice. However, the concerns identified by ACEP limit the ability to assess the demonstrated system, or make recommendations regarding its design, performance, or functionality.

It is recommended that further development of an Alaska-specific design approach to power transmission be conducted as a separate activity from the development of small-scale HVDC converters. There remains considerable work in terms of development and demonstration for this approach as a technology to be commercially ready, and significant safety, reliability, and financial risks to it being adopted by an Alaska utility or operator. Polarconsult should be commended for the extent of effort put into this activity and the progress achieved through this project. This technology, however, is largely complementary to small-scale HVDC transmission, already a pre-commercial technology with major hurdles to overcome in development and demonstration.

It is further recommended that an interested party (e.g., an Alaska utility, operator, or key stakeholder) and an application specific to this as a technology, separate from small-scale HVDC transmission, be identified before further development takes place. Without substantial “buy-in” or involvement with potential utilities or operators, progress toward a commercial product will be difficult. Per the needs and interests of the identified party and application, a revised demonstration should take place that includes a more representative system, a reduction of variables, long-term performance monitoring, and demonstrated functionality of field deployment, maintenance, and operation.

Recommendations regarding development of a SWER system for use in small-scale HVDC transmission are similar. Single-wire earth return is merely complementary to small-scale HVDC transmission; future investigation should be conducted as a separate activity only with significant “buy-in” from key stakeholders. The AKDoL has indicated openness to reviewing the regulations regarding the use of SWER in Alaska. Presumably, this could provide an opportunity to formally investigate the various outstanding technical questions regarding the use of SWER in Alaska conditions. It is recommended that this opportunity be explored further, through the facilitation of an entity such as the Denali Commission, AEA, or ACEP, and only with the involvement of key stakeholders, such as the SAG.

Single-wire earth return remains an intriguing possibility for particular transmission projects in Alaska, whether AC or DC, given supporting Alaska conditions such as a low-density, widely scattered population and very little infrastructure in areas in between population centers. The use and performance of SWER in frozen soils and changing permafrost conditions, however, remain a primary research question for consideration before deployment of such relevant projects.

The economic analysis completed as part of this report suggests that HVDC with SWER may be economical under conditions that are very reasonable to assume. Among these conditions are low population densities and rising costs of diesel. Another condition is a decrease in capital costs as small-scale HVDC products go into volume production. The economic findings of this report are limited, however, given the number of assumptions made for a pre-commercial technology with major hurdles in commercialization to overcome. Cost estimates for the converters and transmission system components have been refined from Phase I findings, but still incorporate considerable uncertainty.

Multi-terminal networks in the context of this technology and scale may be very useful, if not critical, for applications in Alaska given the opportunity to increase economies of scale. Multi-terminal networks have had limited field testing and application, however. It is recommended that this technology be monitored as it is deployed and refined over the next few years, and that lessons learned are captured and integrated into future Alaska small-scale HVDC considerations.

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8.0 Appendices

8.1 Overhead AC Intertie Cost Estimates

Cost Items for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Total Cost
Pre-construction	$39,000	$975,000	$36,000	$900,000	$33,000	$329,000	$2,204,000
Administration/ Management	$18,000	$450,000	$18,000	$450,000	$18,000	$180,000	$1,080,000
Materials	$71,000	$1,775,000	$71,000	$1,775,000	$71,000	$710,000	$4,260,000
Shipping	$33,000	$825,000	$31,000	$783,000	$30,000	$295,000	$1,903,000
Mobilization/ Demobilization	$125,000	$3,125,000	$118,000	$2,958,000	$112,000	$1,115,000	$7,198,000
Labor	$111,000	$2,775,000	$111,000	$2,775,000	$111,000	$1,110,000	$6,660,000
TOTAL	**$397,000**	**$9,925,000**	**$386,000**	**$9,641,000**	**$374,000**	**$3,740,000**	**$23,306,000**

8.1.1: Estimated Cost Items for Overhead AC Intertie in Normal Terrain (author's estimate)

Intertie Estimated Cost in Difficult Terrain	Cost
Project Cost	$23,306,000
per mile without contingency	$388,000
for 21 miles of normal terrain	$8,157,000
for 21 miles of difficult terrain	$9,788,000
for rest of the 39 miles normal terrain	$15,149,000
cost for 60-mile intertie	**$24,937,000**

8.1.2: Estimated Cost for Overhead AC Intertie in Difficult Terrain (author's estimate)

Notes: Table 8.1.2**Error! Reference source not found.** assumes that 21 miles have difficult terrain and that costs will rise by 20% compared with normal terrain to construct an intertie in that terrain. The cost does not include the cost of the substations and contingency costs.

Intertie Estimated Cost with Substations and Contingency	Cost
Pre-construction Activities	$3,400,000
Administration/Management	$1,300,000
Substations and Switchyards	$3,000,000
Overhead Intertie Construction	$24,937,000
Contingency (20%)	$6,527,000
Total Cost for the Intertie and Substations	**$39,164,000**

8.1.3: Estimated Cost Items for Overhead AC Intertie in Difficult Terrain with Substations (author's estimate)

8.2 Overhead HVDC Monopolar 2-wire Intertie Cost Estimates

Cost Items for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Project Cost
Preconstruction	$56,000	$1,400,000	$33,000	$826,000	$30,000	$302,000	$2,528,000
Administration / Management	$17,000	$425,000	$17,000	$425,000	$17,000	$170,000	$1,020,000
Materials (intertie only)	$47,000	$1,175,000	$47,000	$1,175,000	$47,000	$470,000	$2,820,000
Shipping	$25,000	$625,000	$22,000	$544,000	$21,000	$205,000	$1,374,000
Mobilization/ Demobilization	$94,000	$2,350,000	$82,000	$2,045,000	$77,000	$771,000	$5,165,000
Labor	$71,000	$1,775,000	$71,000	$1,775,000	$71,000	$710,000	$4,260,000
TOTAL	**$310,000**	**$7,750,000**	**$272,000**	**$6,789,000**	**$263,000**	**$2,628,000**	**$17,167,000**

8.2.1: Estimated Cost Items for Overhead HVDC Monopolar 2-Wire Intertie in Normal Terrain (author's estimate)

Estimated Cost in Difficult Terrain	
per mile cost	$286,000
for 21 miles of normal terrain	$6,009,000
for 21 miles of difficult terrain	$7,210,000
for rest of the 39 miles normal terrain	$11,159,000
cost for 60-mile intertie	**$18,369,000**

8.2.2: Estimated Cost for Overhead HVDC Monopolar 2-Wire Intertie in Difficult Terrain (author's estimate)

Notes: For difficult terrain the additional cost is ($7,210,000 - $6,009,000) = $1,201,000. The cost does not include the cost of the converter stations and contingency costs.

8.3 Overhead HVDC Monopolar SWER Intertie Cost Estimates

Per Mile Cost Item for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Total Cost for 60-mile Intertie
Preconstruction	$58,000	$1,450,000	$34,000	$856,000	$31,000	$313,000	$2,619,000
Administration/ Management	$13,000	$325,000	$13,000	$325,000	$13,000	$130,000	$780,000
Materials (intertie only)	$48,000	$1,200,000	$48,000	$1,200,000	$48,000	$480,000	$2,880,000
Shipping	$15,000	$375,000	$13,000	$326,000	$12,000	$120,000	$824,000
Mobilization/ Demobilization	$37,000	$925,000	$32,000	$805,000	$30,000	$303,000	$2,033,000
Labor	$67,000	$1,675,000	$67,000	$1,675,000	$67,000	$670,000	$4,020,000
TOTAL	**$238,000**	**$5,950,000**	**$207,000**	**$5,187,000**	**$201,000**	**$2,019,000**	**$13,156,000**

8.3.1: Estimated Cost Items for Overhead HVDC Monopolar SWER Intertie in Normal Terrain (author's estimate)

Estimated Cost in Difficult Terrain	
per mile cost	$219,000
for 21 miles of normal terrain	$4,605,000
for 21 miles of difficult terrain	$5,526,000
for rest of the 39 miles normal terrain	$8,551,000
cost for 60-mile intertie	**$14,077,000**

8.3.2: Estimated Cost for Overhead HVDC Monopolar SWER Intertie in Difficult Terrain (author's estimate)

Notes: For difficult terrain, the additional cost is ($5,526,000 - $4,605,000) = $921,000. The cost does not include the cost of the converter stations and contingency costs.