APPENDIX A

EPS Engineering Report

(This Page Intentionally Left Blank)

Roadbelt Intertie Reconnaissance Engineering Report

EPS Project #19-0490

November 20, 2020

David W. Burlingame, PE
Dr. James W. Cote, PE
Greg Huffman, PE
Tim Mullikin, RLS

Summary of Changes

Version	Date	Comments
0	May 21, 2020	Initial Release to Ahtna Environmental
1	June 16, 2020	Released to Ahtna
2	August 28, 2020	Incorporated Ahtna comments - issued final
3	October 19, 2020	Final report released
4	November 20, 2020	Utility revisions incorporated

Table of Contents

Electric Power Systems Inc. Consulting Engineers

List of Figures

List of Tables

1 Purpose and Scope of the Report

The purpose of this report is to provide a determination on the feasibility of constructing a transmission line from the Alaska Railbelt electrical system near Sutton, through Glennallen, and on to Tok. It will reconnect to the Railbelt electrical system again near Fort Greely, Alaska. Development and construction cost estimates were also developed that can be used to evaluate the line's economic feasibility in the future.

This transmission line would serve as a second transmission line between the southern and northern portions of the Railbelt. It would transmit power from the southern portion of the Railbelt to the Fairbanks area, as well as serve the communities of Glennallen, Valdez and Tok. It will also provide firm, reliable service to Fort Greely.

The feasibility of the line was determined by technical studies to evaluate the ability of the proposed line to transmit the required amount of power, evaluating if a transmission line corridor is possible for the route, and finally developing cost estimates for the proposed transmission line and the equipment needed to allow the line to function when interconnected to the Railbelt.

A key element of the evaluation was an estimate on the line's length and an assessment of possible locations for the line. To estimate the length of the line and evaluate the construction costs, a possible alignment for the line had to be developed. The alignment developed for the feasibility study was based on one of several routes that are possible between the desired interconnection points. It does not represent a recommended or preferred route, but a route thought to be a good route for the basis of cost estimates and electrical studies.

An important aspect of the route is that electrical studies completed for this project indicate that in order to provide meaningful transfer levels between Anchorage and Fairbanks, the line's operating voltage must be 230 kV. The 230 kV operating voltage precludes any consideration of underground cables along the route. This was a consideration in the route used for the feasibility analysis. Land cables at 230 kV are technically feasible in larger systems and are frequently used in larger cities in the Lower 48. The use of 230 kV land cables can be divided into two types, oil-filled cables and solid-dielectric cables. 230 kV oil-filled submarine cables have been in service in Alaska for well over 30 years, but have limited length, and require significant reactive compensation to control the high voltages created by the capacitance of the submarine cables. Due the large amount of capacitance inherent in these cables, they are not feasible for the proposed transmission line. Solid-dielectric cables have significantly lower capacitance that might allow for limited use in the system; however, these cables have not been used in areas of high-frost movement. Without significant study and review, these cables would not be recommended in this application. If used, the solid-dielectric cables may increase the line construction unit costs by 3-4 times per mile.

During the course of the electrical studies, it became apparent that there are significant advantages to an alternative to the line's proposed routing from Sutton – Glennallen – Tok – Fort Greely (Topology 1). For purposes of power transfer from southcentral Alaska to Fort Greely and Fairbanks, a 230 kV line that is routed from Sutton to near Glennallen to Fort Greely with a radial tap to serve Tok (Topology 2), has the ability to transmit larger amounts of power in a more reliable and cost effective manner than Topology 1. Topology 2 has the same ability to serve loads in Glennallen and Tok via the radial line, but the throughput from Sutton to Fort Greely is significantly better. The downside is that the Tok and possibly the Glennallen/Valdez loads would be served from a single transmission line.

The benefits of the proposed line were not quantified during this study. The new transmission line, in either Topology 1 or 2 would allow firm transfers between the south and the north of at least 75 MW and non-firm transfers between the Southern and Northern Railbelt sections to increase from approximately 65-75 MW to 125 MW. The new line would allow future generation to be developed in southcentral Alaska, Fairbanks/interior Alaska, or the Glennallen/Tok area based on economics and not be geographically constrained. The line would allow firm power deliveries to Fort Greely, which would substantially increase not only the amount of power that could be supplied to the facility, but the resiliency of that power. The new line would increase the Railbelt/Roadbelt's ability to accept renewable energy and provide significant spatial diversity for these resources.

2 Transmission Line Description and Designs

2.1 Voltage Selection

Electric Power Systems Inc. (EPS) in conjunction with the Denali Commission and Ahtna Environmental, Inc. completed a reconnaissance engineering study that determined the feasibility and technical details of completing a second proposed interconnection between the Anchorage Bowl region and Fairbanks. The proposed route begins in the existing Railbelt system tying in to the Matanuska Electric Association (MEA) system, traversing east to the Copper Valley Electric Association (CVEA) system in Glennallen, continuing northeast to the Alaska Power & Telephone (AP&T) system in Tok, and finally terminating in the Golden Valley Electric Association (GVEA) system near Delta Junction.

This Roadbelt Intertie would provide a second parallel path for power to flow from South to North thus increasing capacity of the power transfer between GVEA and the Southern Railbelt utilities. In addition, this new path would interconnect the CVEA system and the AP&T system to the existing Railbelt utilities allowing for less expensive power, more reliability for all interconnected utilities, and improved service for Alaska electricity consumers.

The power flow results indicate that 230 kV construction using 795 ACSR (Drake) or 954 kcmil single conductor transmission lines between O'Neill substation in Sutton (MEA), and Jarvis Creek substation in Delta Junction (GVEA) are the top conductor selections, with 795 kcmil used for the final studies and cost estimates. Both topologies that were modeled are feasible. Topology 1 connects directly from Sutton, to Glennallen, to Tok, to Delta Junction in series. Topology 2 connects from Sutton to Glennallen, then directly to Delta Junction with a radial line built at 138 kV from Glennallen to Tok. Both topologies achieve the primary goals of creating a second parallel interconnection and interconnecting CVEA and AP&T.

The transient stability results indicate that the second topology, with a lower voltage radial line to Tok, is generally more stable and requires less controls and reactive support to ensure stability. This is primarily due to the lower electrical distance between MEA and GVEA that can be achieved by building from Sutton to Glennallen to Delta Junction without looping through Tok, but instead, radially connecting from Glennallen to Tok. It is clear that both topologies will require support from GVEA's Wilson Battery Energy Storage System (BESS) and new Static VAr Compensating (SVC) devices along the proposed transmission corridor in order to provide reliable and stable power during contingency events.

Both modeled topologies would be capable of supporting additional generation and load considerably above and beyond that simulated in the studies with little impact to the transfer capability of the line. The electrical studies and their results are presented in more detail in Section 6.

2.2 Route and Construction Assumptions

Generally, we used previous studies, land ownership maps, and wetland and topography maps to develop three possible segments for a 230kV intertie route from Sutton to Glennallen, Tok, and Delta Junction. We avoided wetlands as much as possible to limit the amount of winter construction, as well as steep and inaccessible terrain to limit the amount of more expensive helicopter construction. Routes were also developed to avoid mapped native allotments, State of Alaska Mental Health Trust Authority lands, private parcels, and Alaska Heritage Resources Survey (AHRS) cultural sites. The routes are by no means intended to be the most feasible or the most preferred as they have not gone through the environmental assessment and public scrutiny needed to select a route for final design. Rather they were selected as a reasonable representation for line length, angle structures, and terrain, soil, and access conditions needed to estimate probable construction costs.

2.2.1 Segment 1: Sutton-Glennallen

In 1993 the State of Alaska Division of Energy solicited a feasibility study for a 138 kV transmission line route from Sutton to Glennallen. R. W. Beck provided a detailed feasibility study report (the Beck Report). This incorporated engineering analyses and public comments for four potential routes. We used the “apparent preferred route” identified in the Beck Report as the basis of our cost estimate for this segment. We did not alter the route selected from this study for our estimate. This route begins at a proposed new substation approximately 0.7 miles west of Sutton. It traverses 135 miles east toward Glennallen avoiding the Matanuska Valley Moose Range, native lands, several private parcels, and unpatented mining claims. This route stays north of the Glenn Highway (generally 1-3 miles from the roadway) until it crosses to the south about 6.5 miles west of Glennallen. It avoids most wetland areas until almost 42 miles west of Glennallen where interspersed wetlands are encountered to the terminus at Copper Valley Electric Association (CVEA) Pump Station 11 Substation. Line length of this section is approximately 135 miles.

2.2.2 Segments 2 & 3: Glennallen-Tok & Tok-Delta Junction

The study route from Glennallen to Tok begins at the Pump Station 11 Substation and generally follows the Tok Cut-Off Highway for 142 miles to its terminus at the Tok Power Plant. The route from the Tok Power Plant to Delta Junction generally follows the Alaska Highway for approximately 111 miles to its terminus at the Golden Valley Electric Association (GVEA) Jarvis Creek Substation south of Delta Junction.

Much of these routes are located within the highway corridor, but do veer away to avoid wetlands, culturally sensitive areas, private parcels and native lands. The basis for these routes using existing road right of ways, is to avoid environmentally sensitive areas as much as possible through the mountains and wetlands, while limiting helicopter and winter construction and providing easier access for maintenance.

2.2.3 Radial Option – 138 kV Tap from Lake Louise/Glennallen to Tok

While not within the scope of our cost estimate, we did examine the possibility of revising the above routes by turning north along Segment 1 at Lake Louise Road (approximately 43 miles west of Glennallen) and routing a 230 kV transmission line through the mountains straight to the Jarvis Creek Substation. Assuming this route would require a 138 kV tap from Lake Louise Rd east to Glennallen, then north to the Tok Power Plant, the total approximate lengths for new transmission lines would be 247 miles for 230 kV and 178 miles for 138 kV. Another option would be a radial line from Delta Junction to Tok, which may offer considerable advantages in terrain and topology. These options were not priced since it was not in the scope of work, but the routes have significant benefits for power transfer from Anchorage to Fort Greely/Fairbanks when compared to the proposed route. For the purposes of this study, the Glennallen – Tok radial route modeled as Topology 2 and the Delta Junction – Tok radial route described here are essentially the same in terms of electrical performance.

2.3 Design Criteria

Our electrical studies found 230 kV the optimal voltage and 795 kcmil a feasible conductor size (one conductor per phase) for the intertie. Conductors are available in a variety of materials, types and strandings, with Aluminum Conductor Reinforced with Steel (ACSR) by far the most common type for long distance transmission lines. The steel gives the aluminum conductor additional strength, which reduces sag and allows for longer spans using the same structure height as all-aluminum conductors. U.S. Department of Agriculture Rural Utilities Service (RUS) recommends 795 kcmil as the minimum ACSR size for 230 kV. based on a combination of radio noise, corona, and mechanical sag and strength considerations. "Drake" conductor is a popular 795 kcmil ACSR stranding (26/7), and all Railbelt utilities use it. The Beluga lines all use 795 kcmil ACSR "Drake" and Chugach Electric Association, Inc. (Chugach) has made that conductor size and stranding their standard for both sub-transmission and transmission lines. The University-Eklutna double circuit 230 kV lines uses Drake conductor, as does MEA's Eklutna Generation Station-Hospital Substation double circuit 115 kV line. Drake conductor and associated hardware are also well stocked in GVEA's inventory, since many of their transmission lines use it including the North Pole-Carney 138 kV line and the Clear Switchyard-Clear AFB Substation 230 kV line.

We believe Alaska weather conditions warrant use of a strong ACSR and have based our cost estimates on using 795 kcmil ACSR “Drake” conductor. During final design, heavy loading areas, long spans, or sections of the line may be encountered where conductors even stronger than Drake will better serve the design. Several options are available. These include using aluminum alloy conductor (AACSR), aluminum conductor supported with high-strength or ultra-high strength steels (ACSS/HS or ACSS/HS285), and alumoweld conductor, which consists of high-strength steel strands coated with aluminum. Previous studies for a line between Sutton and Glennallen did not include OHGWs in their design or estimates. This does not contradict the designs of many existing transmission lines in southcentral Alaska, although the interties between Anchorage and Fairbanks have OHGWs installed or have designs that can accommodate the addition of OHGWs. Increased lightning occurrences have been reported in the areas of the Railbelt Intertie in recent years, likely due to changing weather patterns. The section of the line between Glennallen – Tok - Fort Greely may experience considerably higher lightning levels than the Sutton – Glennallen section. For the purposes of estimating costs of the Roadbelt Intertie, we believe it prudent to include OHGWs for the entire line section. Given the importance and price of the project, adding the extra reliability seems prudent. Unless detailed meteorological studies find little chance of lightning strikes, we believe the line should be protected from lightning. A side benefit of installing OHGWs, is they can be used to transmit communications with fiber optic strands in their core (OPGW). OPGWs can either be installed initially, or the higher cost of OPGWs can be deferred to a later date when and if the need for communication lines arises. We have assumed two 7/16” extra-high strength steel OHGWs will be installed for the entire route.

We believe the four loading/construction zones identified in the Beck Report are reasonable and expandable to the Glennallen-Tok-Delta Junction sections. These four zones were initially divided by changes in climate for the purpose of establishing design loads but were also found to roughly parallel changes in terrain, soils, and vegetation. They were therefore taken as equivalent construction zones with distinct construction season, clearing and access needs.

The Beck Report characterizes the four zones as follows:

Zone 1 stretches from Sutton to Caribou Creek in the Matanuska River Valley. It is generally heavily to moderately forested with alder, cottonwood, white spruce, and birch on the western end of the zone. Glacial till is dominant soil type with pockets of muskeg and rock outcroppings. No permafrost is expected, which makes direct embedment foundations practical. There is limited access to the ROW from the Glenn Highway unless the few existing trails can be upgraded for use. Access overland along the ROW is possible. Year-round construction is possible.

Zone 2 lies in the Copper River Basin and east of Syncline Mountain. The terrain is barren at higher elevations and moderately forested with predominantly black spruce from Slide Mountain eastward. The soils are characterized by extensive muskeg, wetlands, and permafrost. No new access roads are assumed, but there will be good access in winter. Construction will take place in winter with foundations using driven piles to minimize the damage to wetland areas.

Zone 3 is located at elevations generally greater than 3,300 feet that did not fit into Zone 4. This includes backcountry valleys in the Talkeetna Mountains. Soils will be mostly glacial till and colluvial with pockets of muskeg and wetlands. No permafrost is anticipated except possibly on north facing slopes. Direct embedment foundations are likely to be practical. Construction will require a combination of helicopter and limited overland access to the ROW. Access along the ROW is assumed practical between major streams. Open lands are prevalent with little or no clearing required. Zone 3 would be mostly non-winter construction with some fringe winter construction likely in wetland/muskeg areas.

Zone 4 includes route segments at high elevations such as the areas north of Strelshla Mountain and Chitna Pass. The dominant soil types are expected to be glacial till and colluvial soils with increased presence of rock. Zone 4 will require all-helicopter construction with no overland access assumed. Construction would be restricted to non-winter periods only. No clearing is anticipated.

For the Glennallen–Tok–Delta Junction sections, we believe Zone 2 loading and construction is a reasonable fit, except there are sections where direct embedment foundations and non-winter construction will be possible. Our cost estimates assume a 50/50 split for direct embedment and pile foundations for the 253 miles between Glennallen and Delta Junction. Loading for Zone 1 applies to approximately the first 37 miles of line coming from Sutton. It is typical of loading used on lines in the Anchorage bowl and Mat-Su areas except for the extreme combined ice/snow and wind load case. This load case applies 2.5 inches of radial wet snow or rime ice (30 pcf) to the conductors in combination with 20 mph (1 psf) winds. This large accumulation of snow on the conductors is equivalent to 1.69 inches of radial glazed ice (57 pcf). This loading will control the vertical strengths of the cross arms, suspension insulator assemblies, etc. It would also control structure heights if it was a criterion for the design ground clearances. We believe it is reasonable to design structure strength for this loading, but not to include it as a ground clearance condition due to its anticipated rare and short duration occurrences. Rather, the extreme ice loading (1 inch radial glazed ice) will control ground clearances.

NESC Heavy and Extreme Loadings for Zones 2 and 3 are the same as Zone 1 except they are assumed to occur at colder temperatures. Both of these zones use 1.5 inches of radial ice for the extreme ice loading, which will control structure heights (ground clearances) and vertical strengths. Zone 2 is by far the most commonly used for the selected routes and is characterized by relatively flat terrain with high probability need for deep pile foundations and winter construction. Zone 3 is used for about 32 miles between Sutton and Glennallen where elevations exceed 3,300 feet.

Zone 4 is only used for about 4 miles in the high elevation areas (Strelshla Mountain and Chitna Pass) in between Sutton and Glennallen. Its loading conditions are expected to be the worst of the entire intertie. Extreme wind loading is assumed to be 125 mph (40 psf) and extreme ice loading assumes 2 inches of radial ice. The extreme combined ice/snow and wind loading is based on 2 inches of radial glazed ice in combination with 75 mph (14 psf) wind. This loading case will control the design for this zone, being more than twice the unit transverse loading of the other zones.

Table 1 below lists the design loading criteria from the Beck Report with our recommended adjustments noted in the footnotes.

Table 1: Assumed Study Design Criteria

LOAD CASE	PAREMETER	UNIT	ZONE 1	ZONE 2	ZONE 3	ZONE 4
NESC Heavy	Radial Ice	in	0.5	0.5	0.5	0.5
	Wind Speed	mph	40	40	40	40
	Wind Force	lb/sf	4	4	4	4
	Temperature	˚F	0	-20 (1)	-20 (1)	-20 (1)
	Wind L. F.	-	2.50	2.50	2.50	2.50
	Vertical L. F.	-	1.50	1.50	1.50	1.50
	Tension L. F.	-	1.65	1.65	1.65	1.65
Extreme Ice	Radial Ice	in	1.0	1.5	1.5	2.0
	Temperature	˚F	30	20	20	20
	Wind L. F.	-	1.10	1.10	1.10	1.10
	Vertical L. F.	-	1.10	1.10	1.10	1.10
	Tension L. F.	-	1.10	1.10	1.10	1.10
Extreme Wind	Wind Speed	mph	100	100	100	125
	Wind Force	lb/sf	26	26	26	40
	Temperature	˚F	20	10	10	10
	Wind L. F.	-	1.10	1.10	1.10	1.10
	Vertical L. F.	-	1.10	1.10	1.10	1.10
	Tension L. F.	-	1.10	1.10	1.10	1.10
Extreme Combined Ice/snow and Wind (2)	Radial Ice	in	0.0	1.0	1.5	2.0
	Radial Snow	in	2.5	0.0	0.0	0.0
	Snow Density	pcf	30	n/a	n/a	n/a
	Ice Equiv.	in	1.69	1.00	1.50	2.00
	Wind Speed	mph	20	40	40	75
	Wind Force	lb/sf	1	4	4	14
	Temperature	˚F	30	20	20	20
	Wind L. F.	-	1.10	1.10	1.10	1.10
	Vertical L. F.	-	1.10	1.10	1.10	1.10
	Tension L. F.	-	1.10	1.10	1.10	1.10

(1) EPS recommends using a reduced temerature for NESC Heavy Loading in Zones 2, 3 and 4.
(2) The Extreme Combined Ice/Snow and Wind load case is used for structure strength but is not considered for ground clearances.

The NESC requires minimum ground clearance for 230 kV lines of 18.5 feet for areas non-accessible to vehicular traffic, and 22.5 feet for areas susceptible to vehicular traffic. We believe several feet of contingency should be added to these values to account for survey and construction tolerances, snow ground cover, and increased sag due to unbalanced snow/ice conditions. We propose adding about six feet of contingency for Zone 2, and 12 feet contingency for Zones 1, 3, and 4.

2.4 Alaskan Transmission Line Discussion

The first long-distance, high-voltage, lines built in southcentral Alaska typically used wood H-frame or aluminum lattice X-towers or Y-towers for tangent structures (the structures that support the transmission line along fairly straight runs).

Wood H-Frame Steel X-Tower Steel Y-Tower

Wood H-frames were direct embedded into the ground and sometimes used cross-bracing. The cross bracing allows for the use of lighter poles by making the structure act as a braced frame in the transverse direction (direction perpendicular to the line). Angle structures were guyed. Medium to large angle structures typically used one pole for each phase resulting in three poles. This type of construction is economical but has a relatively short life expectancy of 40-60 years due to the natural deterioration of wood poles. Wood poles are also susceptible to insect, woodpecker, bear, and fire damage.

We do not recommend the use of cross bracing (X-bracing) on new construction in Alaska for several reasons. A cross-braced structure is strong and stiff in the plane of the frame, but it still behaves as a cantilever structure in the longitudinal direction (direction parallel to the line). This presents some weaknesses in the structure system, such as possible insufficient strength for longitudinal loading caused by differential ice loading on the conductors, avalanche loading, the lack of flexibility to resist foundation movement (i.e. pile jacking), and poor dynamic behavior caused by earthquakes, avalanches, etc. It is noted that the 1964 Alaska earthquake caused significant damage to some braced H-frames, but no or minimal damage to adjacent unbraced H-frames.

Our experience is there is no cost savings in using braced H-frames in Alaska. The material, shipping and labor costs to install the braces in Alaska usually outweigh the cost savings of using lighter poles. We believe you get a universally stronger and more flexible structure by not using cross braces at approximately the same cost of using cross braces.

Aluminum lattice X-towers are used for several circuits of 138 kV and 230 kV transmission from the Beluga Power plant to Pt. Mackenzie and Teeland Substations in the Anchorage–Wasilla area. They were chosen for their light weight, simple hinged structure, foundation attachment, and the flexibility to survive pile jacking. Using lattice members (angle shapes bolted into a truss configuration) is an effective way to minimize structural materials. Aluminum alloy metals offer a good strength to weight ratio. Most of the aluminum lattice X-towers weigh less than 10,000 lbs.

Aluminum Lattice X-Tower

Aluminum Lattice Y-Tower

Using hinged or pinned connections to the foundations also saves structure weight and foundation costs because it allows the structure to behave as a truss (or in the case of guyed structures, as a strut) where structure members are predominantly axial loaded and have to resist very little bending moment. If designed to do so, hinged and pinned base structures can also be easily rotated from a horizontal position to a vertical position and vice versa. Most of the X-towers use driven H-pile foundations than can be installed with relatively light, all-terrain equipment such as Nodwells. The towers are guyed fore and aft with two guys on each side sharing a common anchor (total of four guys, two anchors and two foundations). The guys usually incorporate a breakaway or collapsible mechanism to relieve guy tension in the event of foundation jacking or extreme longitudinal loading.

Lattice X-towers are conducive to remote, lowland construction where the terrain is generally flat, and wetland and soil conditions necessitate winter construction. Lightweight tracked equipment can be used to drive piles for foundations and anchors. It can also be used to transport and erect the towers. The towers can survive moderate pile jacking and/or anchor pullout before they require repairs. Also, pile foundation repairs are relatively easy because a leg of the lightweight towers can easily be disconnected from its foundation while the pile is re-driven.

Medium to large angle and dead-end structures on the Beluga lines consist of three aluminum lattice masts that are pin connected to their foundation and guyed in multiple directions.

The Beluga lines have held up fairly well over time with few structural problems other than occasional pile jacking.

The Healy to Fairbanks 138 kV line was constructed in the mid 1960s using aluminum lattice Y-towers. Like the aluminum lattice X-tower, it is a lightweight structure with a pinned foundation connection. It requires only one foundation, but four guys and anchors. This line uses guyed aluminum lattice mast structures for angle structures similar to the Beluga lines. It still operates in fairly good condition today. It too has experienced some pile jacking, but mostly to the masts of the angle structures. The Y-towers have not experienced much pile jacking. This is likely because they are guyed and anchored in four directions with enough strength to resist the upward push of the single foundation. The mast structures on the other hand are guyed strongly to resist the wire tensions due to the line angle, but not in enough directions to resist the foundation jacking. Many of these masts have experienced upward and outward (lean away from the resultant of the conductor tensions) displacement.

Since the 1960s and '70s, use of aluminum transmission line structures has become almost obsolete due to the much more favorable pricing of steel. Lattice structures are also not used nearly as much, except for the very high voltage lines where structures need to be broader (for increased phase spacing), taller (for increased ground clearance and longer spans) and stronger (for larger or bundled conductors and longer spans).

The advent of large brake presses, which can form steel plate into long, tapered, tubes with polygon-shaped cross sections, started to make tubular steel structures more economical than lattice structures in the 1970s for transmission lines up to about 345 kV. Tapered members save material by using smaller tube diameters where there is less loading, and 6, 8, 12 and 16-sided polygon-shaped sections allow more efficient use of the material to resist loading. Although tubular steel structures are still heavier than lattice structures, they are much less labor intensive to assemble.

Given the successful performance of lattice X-towers, tubular steel X-towers began to be used for major Alaska transmission lines in the post oil boom era, including the Anchorage to Fairbanks 345 kV Intertie (Willow to Healy), the Solomon Gulch 138 kV line (Valdez to Glennallen), the Tyee 138 kV line (Wrangell/Petersburg), the Bradley Lake line (Homer), and the Northern 230 kV Intertie (Healy to Fairbanks). However, use of X-towers in hilly and mountainous terrain caused problems not found in the low flatlands they were originally designed for. Instead of deep pile foundations used for the wet, deep-organic soils of lowlands, shallower foundations were often used for the mineral soils of the uplands. These included direct embedded pile sections and grout-anchored concrete blocks. There have been several cases of soils eroding from around these shallow foundations to the extent that they can no longer resist the spreading effect from the tower's legs.

A X-tower installed on uneven terrain requires either one high reveal foundation, or differential leg lengths. In order for a X-tower with uneven legs to be tilted up or laid down, the hinge axis of each leg must be colinear, or special pinned connections, such as ball and socket types, must be used to provide an axis of rotation that bisects each leg's pinned connection. Another problem found with using X-towers in rolling terrain is the increased chance of damage from wind vibration. Long, slender, circular members, such as the legs of tall tubular steel X-towers, are prone to severe fatigue damage under certain wind conditions that cause the members to vibrate at a high frequency. These wind conditions typically are laminar and less than 20 mph. They occur more often in hilly terrain where funneling and channeling can occur, than in open flatlands where winds are gustier.

Other structure types used in recent years for long transmission lines in Alaska include tubular steel, guyed Vee towers for the Tyee 138 kV line improvements, and tubular steel Y-towers for the Swan–Tyee 138 kV Intertie. The guyed Vee towers used to improve the Tyee line are similar to guyed Y-towers, in that they have a single pinned-base foundation and a guy and anchor in four quadrants. They were inserted in almost every span of the existing line to improve ground clearances. They were flown to each site in an "H" configuration with a helicopter and lowered in between the existing conductors. Ground crews then pulled the legs together, pinned them to the foundation, and attached the guys to the anchors before the helicopter released the structure.

The Swan-Tyee Intertie was installed in the rough mountainous region of southeast Alaska. Access to almost every structure site was by helicopter only. This required use of innovative foundation and structure systems. Foundations consist of micro-pile clusters and the basic tangent structure type is un-guyed, tubular steel Y-towers.

All of the lines and structure types mentioned thus far are single circuit with three phases configured in a flat or horizontal position. They use free-swinging, suspension type insulators on their non-deadend structures. This is an economical construction type for long lines where adequate right of way is available. It allows for longer spans, which usually prove to be more economical. It also prevents phase contacts that can occur on vertically- configured structures when heavy ice-loaded upper conductors sag down into lower conductors with no or little ice, or when conductors shed their ice and "jump."

Transmission line designers must be careful not to stretch the span lengths too far, especially for lines using over-sized conductors for their immediate needs. The Anchorage-Fairbanks (Willow-Healy) line for example was designed for future 345 kV using bundled 954 kcmil conductor and long spans. It is operated at 138 KV and has had chronic problems at the southern end with ice/snow loaded conductors sagging down to near the ground. The electrical load on the line is often too little to thermally heat the conductors enough to prevent heavy ice and snow accumulations. The additional sag is compounded when adjacent spans drop their ice or snow, causing large tension differentials in the conductors. The differential tensions cause the suspension insulators to swing towards the higher-tension span, adding slack and sag to the iced span.

The original Tyee 138 kV line had similar problems until span lengths were drastically reduced by insetting new Vee structures in between the original structures. The Solomon Gulch 138 kV line has also experienced several ice/snow-loaded clearance problems.

If vertically configured structures are used in high ice-prone areas such as southcentral Alaska, they should be used only for short spans or where plenty of vertical separation has been incorporated into the design. Double circuit lines usually have no choice other than be vertically configured. They typically use davit arms with suspension or Vee insulators, or horizontally braced (horizontal Vee) insulator system.

Isokeraunic levels in southcentral Alaska have historically been low, and many of the major transmission lines in the state have operated reliably without any lightning protection. A couple of the lines previously mentioned, the Anchorage–Fairbanks 345 kV Intertie (Willow–Healy), and the Healy–Fairbanks 138 kV line along the Parks Highway, do have overhead ground wires (OHGW) for lightning protection. The Northern 230 kV Intertie (Healy–Fairbanks) was designed for an optical ground wire (OPGW), which is an overhead ground wire with interior fiber optics, and an OHGW. These were never installed due to budget constraints. GVEA is the only Alaska utility that routinely installs OHGWs on their transmission lines.

The selection of a structure type is highly dependent of soil conditions, foundation type, terrain conditions, and access. Foundations are a major contributor to the cost of transmission lines, especially in Alaska where remote conditions, soils with deep organics and/or permafrost, and frost jacking are prevalent.

Structure sites accessible to heavy equipment can afford to have heavy, moment-resisting foundations such as those needed for un-guyed structures. Sites inaccessible by overland equipment must use helicopter compatible equipment such as Menzie Mucks (walking spider excavator) and portable drilling units. These types of equipment are not capable of excavating deep holes or driving large piles. Deep foundations at these locations must therefore use rock anchors or micro-piles. These foundation units resist axial loading well but are not adept to resisting large lateral or overturning loads without clustering several of them together. Pinned-base structures such as guyed Y-towers would work well for helicopter construction because the structures are light-weight and the supporting foundations and anchors are predominantly axial loaded and can be installed with helicopter compatible equipment. In extremely rugged terrain, helicopters may be needed to move equipment between each foundation and anchor location at the same site so minimizing the number of ground penetrations may become important.

The Beck Report evaluated seven different structure types; 1) single steel pole, 2) single wood pole, 3) guyed steel X-frame, 4) unbraced steel H-frame, 5) braced steel H-frame, 6) unbraced wood H-frame, and 7) braced wood H-frame. Because of weight, strength, and flexibility restrictions, only the guyed steel X-frame and unbraced steel H-frame were considered applicable to all zones. That report found the unbraced steel H-frame to be the most economical structure type and assumed its use for the entire route between Sutton and Glennallen in their cost estimates. We do not dispute this structure type is a feasible choice, especially in areas where overland access is available and frost jacking is not a huge concern. This would include Zone 1 and many sections of Zone 2 between Glennallen and Delta Junction. It may be possible to save some capital costs by using wood H-frames in these areas, but wood does not provide the reliability, longevity, nor fire-resistance that steel does. It is noted that CVEA has had problems with carpenter ants hollowing their wood poles in the Copper River Basin, and Homer Electric Association has had problems with bears eating or otherwise damaging wood poles in their service area.

We also assumed the use of steel H-frames for the entire length of the intertie. Angle and deadend structures are assumed to be guyed 3-pole tubular steel masts with the same foundation types used for the tangent H-frame structures. Typical H-frame and 3-pole running angle structures are shown in Figures A and B (Appendix A). Should this project progress to final design, a detailed structure study should be performed to determine the best structure and foundations types for the various sections of the intertie. We suspect steel X-towers will be competitive with the steel H-frame in Zone 2, especially in wetland and deep organic soil areas where frost jacking is most likely to occur. The X-tower is lighter and responds better to frost jacking than H-frames do. Smaller and more standardized pile foundations can be used with X-towers because their leg attachments are hinged or pinned (no overturning moment), and there is relatively little change in base reactions with changes in tower height. The X-tower also offers easier repairs for its foundations and better longitudinal loading capacity since it is guyed fore and aft.

But X-towers are more complicated to design, fabricate and assemble than are steel H-frames, so their cost may not necessarily be less despite being lighter in weight. X-towers also require longitudinal guys and anchors, requiring twice the ground setups/penetrations as self-supporting H-frames.

Although the high elevations of Zone 4 make up a very small fraction of the total intertie route, it will be the costliest to construct on a per mile basis. The extreme loading conditions and difficult access (all helicopter access assumed) will likely make its per mile construction costs 40% - 65% greater than the other line sections. Again, there may be a more economical structure type that is better suited for this section than the steel H-frame. Rock anchors and micro-piles will be the likely foundation and anchor type and a lightweight structure system relying on axial base reactions, such as guyed Y-towers will save on structure and foundation costs. This cost savings will need to be weighed against the cost of extra ground setups/penetrations for the five foundation/anchors needed for guyed Y-towers, versus two needed for steel H-frames.

3 Transmission Cost Estimates

3.1 Transmission Line Construction Costs

We broke the intertie route into five segments, and estimated construction costs for each segment individually. The five segments are the four zones defined in the Beck Report, with the addition of a fifth segment comprised of the long section from Glennallen to Delta Junction. Approximate line lengths, angle structures, uplift structures and long span structures were estimated from the route corridors previously discussed. Ruling span and average span lengths were chosen for each segment based on our experience with similar transmission lines in Alaska. Considerations for this include structure heights and strengths, right of way width, and clearance issues caused by heavy ice/snow loading. A 120-foot-wide ROW was assumed for the study, and maximum span lengths were calculated to keep the conductors within the ROW under extreme wind conditions. Table 2 provides a summary of the spans used for each segment, along with typical phase spacings used with the ROW width and span lengths.

Table 2: Design Loading Criteria

	Sutton to Glennallen				Glennallen to Delta Junction
	Zone 1	Zone 2	Zone 3	Zone 4	Zone 2
Ruling Span, ft.	900	900	900	750	900
Average Span, ft.	800	850	800	650	850
Max. Span for 120’ ROW, ft.	1050	1000	1000	850	1000
Phase Spacing, ft.	18	18	18	17	18

ROW widths should be further studied if this project progresses. Wider ROW may be needed where longer spans are desired. But for the purposes of estimating transmission line costs, we universally used 120 feet as the standard ROW width for the anticipated structure type and span lengths.

Quantities of tangent structures for each segment were estimated by dividing the segment length by the average span length and deducting the angle, deadend and special structure quantities. A typical structure height was calculated using design ground clearances, maximum sags, and structure configuration. Structure strength and weights were then estimated by applying the design loading and using basic principles of steel pole sizing.

Assumed foundation and anchor types include:

Zone 1*:* direct embedment foundations with concrete slug or helical (screw) anchors

Zone 2, Sutton - Glennallen*:* driven pipe pile foundations and anchors

Zone 3*:* direct embedment foundations with concrete slug or helical (screw) anchors

Zone 4*:* rock anchor and micro-pile foundations and anchors

Zone 2, Glennallen – Delta Jct.*:* 50% driven pipe pile foundations and anchors and 50% direct embedment foundations with concrete slug or helical (screw) anchors

Unit costs for ROW clearing, structures, foundations, guys, anchors, framing, conductor, and accessories were used to estimate the construction cost. Unit costs were taken from recent, Alaska transmission lines using similar construction. Unit costs were adjusted for inflation and dissimilarities in construction types and locations. Nominal costs were included for construction surveys and camp costs. Mobilization/demobilization costs were assumed to be 5% of the total construction costs.

No costs were included for communication attachments, or underbuild facilities. Costs for two shield or static wires were included in the estimates.

A summary of the estimated unit construction costs per mile for each of the five line segments are presented in Table 3 as follows:

Table 3: Transmission Line Budgetary Unit Construction Costs per Mile

	Sutton to Glennallen				Glennallen to Delta Junction
	Zone 1	Zone 2	Zone 3	Zone 4	Zone 2
Approx. Construction Cost per mile	$816k	$961k	$894k	$1,448k	$844k

The average construction cost per mile for the entire 388-mile-long intertie was estimated to be $871k/mile, excluding contingency.

Reasonable contingencies need to be applied to our construction estimates based on the many unknowns and assumptions made for this high-level engineering study. A route has not been selected, geotechnical and environmental studies have not been made, and it is not known what effects the current COVID-19 pandemic or other conditions will have on the transmission line material and labor markets during procurement and construction. These issues may increase or decrease line costs, but we believe it prudent to base our project development cost estimates on “bad-case scenarios” by including sizable contingencies that increase costs. We have included a 15% contingency on material costs and 25% on installation (labor) costs. Total intertie construction cost is estimated to be $410 million, or $1,056k/mile, with these contingencies.

Non-construction costs also must be included in the total development cost estimate. These include engineering services (surveying, geotechnical, meteorological, and line design), right of way services (title, surveying, appraisal, and land acquisition), regulatory permitting (DNR, DOT, FAA, BLM, Mat-Su Borough, DoD, etc.), environmental studies and permits (NEPA Process/EIS, public meetings, ADF&G, Corps/ADEC permits, etc.), construction management, and owner costs. We have assumed construction management fees will be 5% of the total construction costs, owner costs will be 5% of the total project costs, and have included a 10% contingency on all non-construction costs.

Non-construction costs specific to the transmission line were estimated as follows:

LIDAR Mob	$78k
LIDAR	$582k
Geotech investigation	$2,000k
Meteorological study	$150k
Transmission design	$3,500k

3.2 Transmission Line O&M Costs

Based on transmission line costs provided by GVEA and CVEA, we estimate the operation and maintenance (O&M) costs associated with the transmission line to be $400k/year for the first 10 years and $800k/year for the remainder of the project’s assumed 50 year life.

4 Substation and Communication System Modification Costs

System studies indicate that modifications will be required at four existing substation locations; namely, MEA's O'Neill Substation near Sutton, CVEA's Pump Station 11 Substation near Glennallen, AP&T's Tok Substation, and GVEA's Jarvis Creek Substation near Delta Junction. In addition, some system-wide communication system modifications are needed.

4.1 Substation Modification Costs

Budgetary cost estimates for substation modifications were prepared based on the design configurations documented in the following sub-sections.

4.1.1 O'Neill Substation

O'Neill Substation is an existing MEA substation that serves MEA's distribution system along the Glenn Highway. The station will require a complete reconstruction to add 115 kV protective breakers, a 230 kV protective breaker, a 115 kV to 230 kV 75 MVA transformer, and a line connected reactor. This equipment will be installed in a new or rebuilt station in the vicinity of the existing station that includes ground grid, protection controls, control building and other miscellaneous equipment.

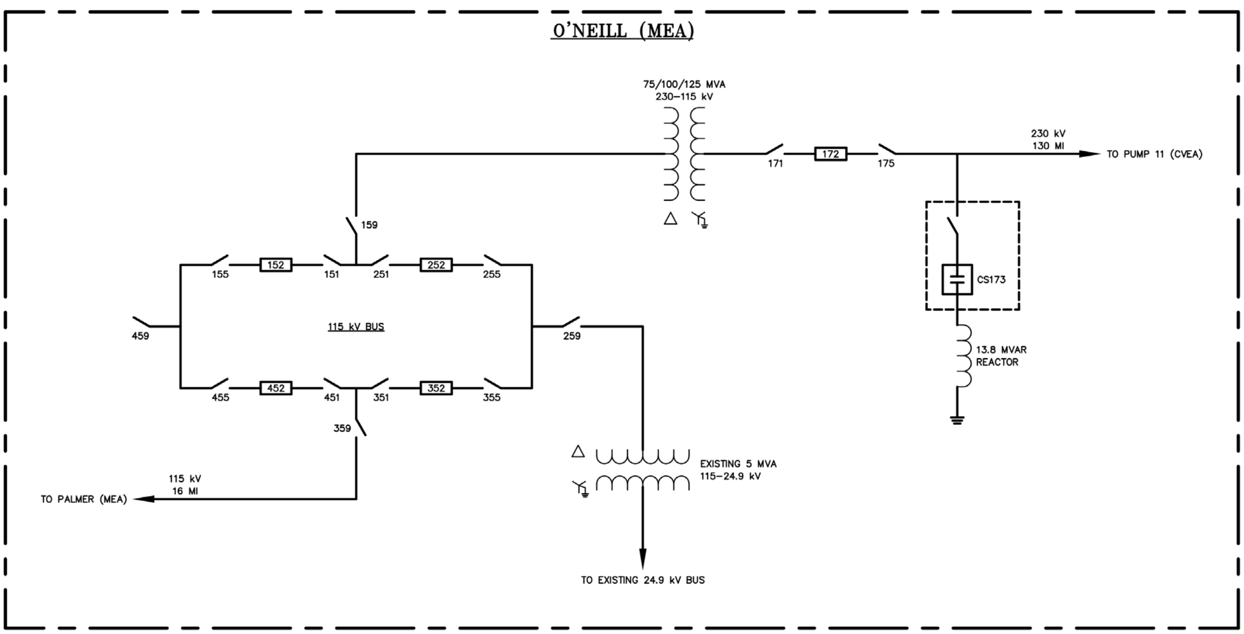


Figure 1: O'Neill Substation Modification One-Line Diagram

Item Description	Extended Contractor Labor	Extended Contractor Material	Extended OFM	Extended Total
GROUP A: STRUCTURES	302,400	19,000	239,600	561,000
Unassigned	302,400	19,000	239,600	561,000
GROUP B: SWITCHING	25,200	9,450	172,000	206,650
Unassigned	25,200	9,450	172,000	206,650
GROUP C: CIRCUITS AND BUSWORK	229,446	155,500		384,946
Unassigned	229,446	155,500		384,946
GROUP E: CIRCUIT BREAKERS	109,200	2,200	550,000	661,400
Unassigned	109,200	2,200	550,000	661,400
GROUP F: FOUNDATIONS	421,901	45,051		466,952
Unassigned	421,901	45,051		466,952
GROUP G: TRANSFORMERS	143,920	28,200	3,092,600	3,264,720
Unassigned	143,920	28,200	3,092,600	3,264,720
GROUP K: CONDUIT AND CABLE	151,313	134,915		286,228
Unassigned	151,313	134,915		286,228
GROUP M: SITE WORK	486,275	146,650		632,925
Unassigned	486,275	146,650		632,925
GROUP N: FENCE AND SIGNS	91,800	209,090		300,890
Unassigned	91,800	209,090		300,890
GROUP O: GROUNDING	217,159	154,356		371,515
Unassigned	217,159	154,356		371,515
GROUP Q: SWITCHGEAR	67,200	25,000	1,000,000	1,092,200
Unassigned	67,200	25,000	1,000,000	1,092,200
GROUP S: YARD LIGHTS	17,323	10,260	9,675	37,257
Unassigned	17,323	10,260	9,675	37,257
Total	2,263,137	939,672	5,063,875	8,266,683
Insurance (3% on CL & CM)				96,084
Contingency (10% on CL & CM)				320,281
Mob/Demob (5% on CL & CM)				160,140
Heated Equip Storage (0.5% on CM & OFM)				30,018
Engineering (12% on CL, CM, & OFM))				992,002
Project Management (3% on CL, CM, & OFM))				248,001
Subtotal				10,113,209
Performance Bond				56,000
Total Estimate				10,169,209

Figure 2: O'Neill Substation Budgetary Cost Estimate

4.1.2 Pump Station 11 Substation

Pump Station 11 is an existing CVEA substation that serves as a major delivery point in their 138 kV system between Glennallen and Valdez. The station would be expanded to include a 230 kV ring bus, a line connected reactor to each 230 kV line terminal, a 138 kV/ 230 kV 50 MVA transformer, a Static VAR system and a tie to CVEA's existing 138 kV bus.

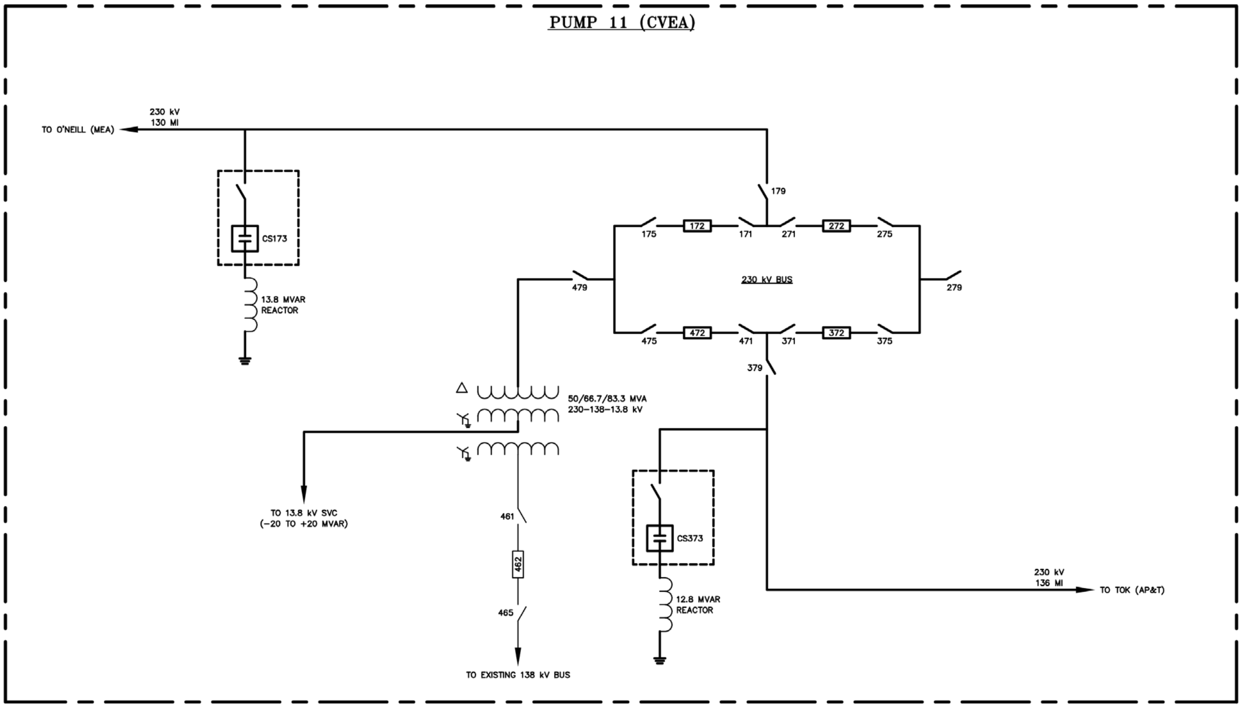


Figure 3: Pump Station 11 Substation Modification One-Line Diagram

Engineer's Estimate Summary

Item Description	Extended Contractor Labor	Extended Contractor Material	Extended OFM	Extended Total
GROUP A: STRUCTURES	330,400	21,000	254,600	606,000
Unassigned	330,400	21,000	254,600	606,000
GROUP B: SWITCHING	95,000	9,450	192,000	296,450
Unassigned	95,000	9,450	192,000	296,450
GROUP C: CIRCUITS AND BUSWORK	237,846	156,250		394,096
Unassigned	237,846	156,250		394,096
GROUP E: CIRCUIT BREAKERS	151,200	3,300	875,000	1,029,500
Unassigned	151,200	3,300	875,000	1,029,500
GROUP F: FOUNDATIONS	539,109	55,159		594,268
Unassigned	539,109	55,159		594,268
GROUP G: TRANSFORMERS	140,000	34,150	3,494,600	3,668,750
Unassigned	140,000	34,150	3,494,600	3,668,750
GROUP K: CONDUIT AND CABLE	214,550	190,290		404,839
Unassigned	214,550	190,290		404,839
GROUP M: SITE WORK	498,573	154,483		653,056
Unassigned	498,573	154,483		653,056
GROUP N: FENCE AND SIGNS	91,800	209,090		300,890
Unassigned	91,800	209,090		300,890
GROUP O: GROUNDING	217,159	154,356		371,515
Unassigned	217,159	154,356		371,515
GROUP Q: SWITCHGEAR	67,200	25,000	1,000,000	1,092,200
Unassigned	67,200	25,000	1,000,000	1,092,200
GROUP S: YARD LIGHTS	43,290	29,120	24,187	96,596
Unassigned	43,290	29,120	24,187	96,596
GROUP U: SVC			11,000,000	11,000,000
Unassigned			11,000,000	11,000,000
Total	2,626,126	1,041,648	16,840,387	20,508,160
Insurance (3%)				110,033
Contingency (10%)				366,777
Mobilization/Demobilization (5%)				183,389
Heated Equipment Storage (0.5%)				89,410
Engineering (12%)				2,460,979
Project Management (3%)				615,245
Subtotal				24,333,993
Performance Bond				56,000
Total Estimate				24,389,993

Figure 4: Pump Station 11 Substation Budgetary Cost Estimate

4.1.3 Tok Substation

Tok Substation is a new substation. It includes a 230 kV line reactor to both Pump 11 and Jarvis Substations, a 12 MVA 24.9 kV/230 kV transformer, a 4-breaker 230 kV ring bus and a connection to the Tok 24.9 kV system.

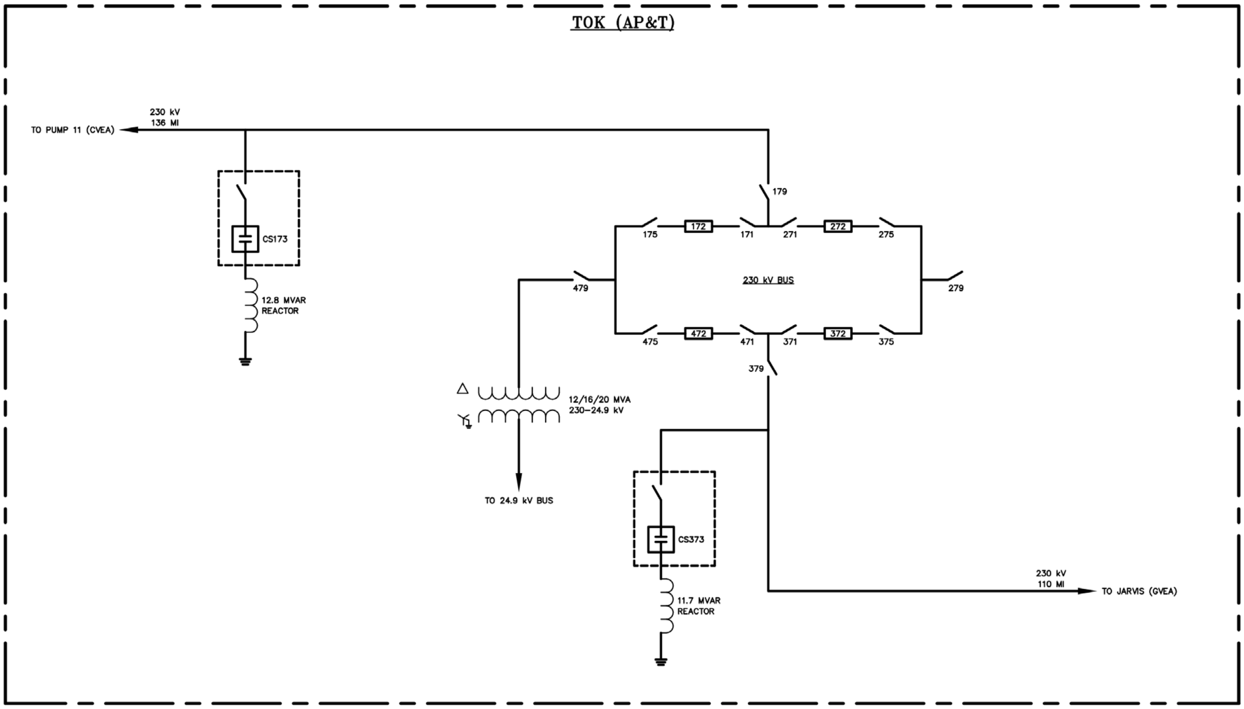


Figure 5: Tok Substation Modification One-Line Diagram

Engineer's Estimate Summary

Item Description	Extended Contractor Labor	Extended Contractor Material	Extended OFM	Extended Total
GROUP A: STRUCTURES	296,800	19,000	235,400	551,200
Unassigned	296,800	19,000	235,400	551,200
GROUP B: SWITCHING	84,000	8,100	168,000	260,100
Unassigned	84,000	8,100	168,000	260,100
GROUP C: CIRCUITS AND BUSWORK	237,846	156,250		394,096
Unassigned	237,846	156,250		394,096
GROUP E: CIRCUIT BREAKERS	134,400	3,000	810,000	947,400
Unassigned	134,400	3,000	810,000	947,400
GROUP F: FOUNDATIONS	524,103	53,221		577,324
Unassigned	524,103	53,221		577,324
GROUP G: TRANSFORMERS	135,520	31,100	2,431,600	2,598,220
Unassigned	135,520	31,100	2,431,600	2,598,220
GROUP K: CONDUIT AND CABLE	214,550	190,290		404,839
Unassigned	214,550	190,290		404,839
GROUP M: SITE WORK	498,573	154,483		653,056
Unassigned	498,573	154,483		653,056
GROUP N: FENCE AND SIGNS	91,800	209,090		300,890
Unassigned	91,800	209,090		300,890
GROUP O: GROUNDING	217,159	154,356		371,515
Unassigned	217,159	154,356		371,515
GROUP Q: SWITCHGEAR	67,200	25,000	1,000,000	1,092,200
Unassigned	67,200	25,000	1,000,000	1,092,200
GROUP S: YARD LIGHTS	43,290	29,120	24,187	96,596
Unassigned	43,290	29,120	24,187	96,596
Total	2,545,240	1,033,010	4,669,187	8,247,436
Insurance (3% on CL & CM)				**107,347**
Contingency (10% on CL & CM)				**357,825**
Mob/Demob (5% on CL & CM)				**178,912**
Heated Equip Storage (0.5% on CM & OFM)				**28,511**
Engineering (12% on CL, CM, & OFM)				**989,692**
Project Management (3% on CL, CM, & OFM)				**247,423**
Subtotal				**10,157,148**
Performance Bond				**56,000**
Total Estimate				**10,213,148**

Figure 6: Tok Substation Budgetary Cost Estimate

4.1.4 Jarvis Creek Substation

Jarvis Creek Substation is a modification to an existing GVEA substation. It includes the expansion of the station to include a new 138 kV bay and a 138 kV/ 230 kV transformer.

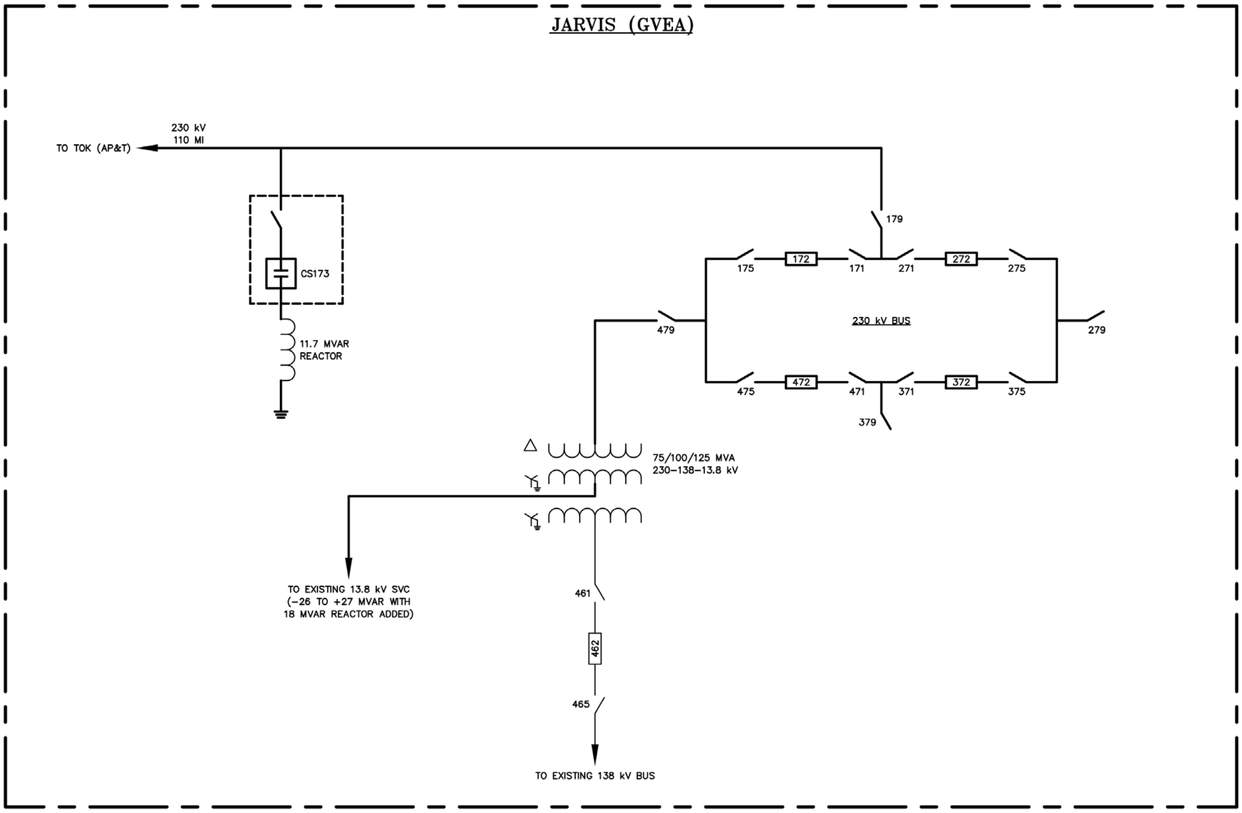


Figure 7: Jarvis Creek Substation Modification One-Line Diagram

Item Description	Extended Contractor Labor	Extended Contractor Material	Extended OFM	Extended Total
GROUP A: STRUCTURES	330,400	21,000	254,600	606,000
Unassigned	330,400	21,000	254,600	606,000
GROUP B: SWITCHING	95,000	9,450	192,000	296,450
Unassigned	95,000	9,450	192,000	296,450
GROUP C: CIRCUITS AND BUSWORK	237,846	156,250		394,096
Unassigned	237,846	156,250		394,096
GROUP E: CIRCUIT BREAKERS	134,400	2,800	700,000	837,200
Unassigned	134,400	2,800	700,000	837,200
GROUP F: FOUNDATIONS	453,384	49,117		502,501
Unassigned	453,384	49,117		502,501
GROUP G: TRANSFORMERS	114,800	28,350	2,819,600	2,962,750
Unassigned	114,800	28,350	2,819,600	2,962,750
GROUP K: CONDUIT AND CABLE	214,550	190,290		404,839
Unassigned	214,550	190,290		404,839
GROUP M: SITE WORK	498,573	154,483		653,056
Unassigned	498,573	154,483		653,056
GROUP N: FENCE AND SIGNS	91,800	209,090		300,890
Unassigned	91,800	209,090		300,890
GROUP O: GROUNDING	217,159	154,356		371,515
Unassigned	217,159	154,356		371,515
GROUP Q: SWITCHGEAR	67,200	25,000	1,000,000	1,092,200
Unassigned	67,200	25,000	1,000,000	1,092,200
GROUP S: YARD LIGHTS	43,290	29,120	24,187	96,596
Unassigned	43,290	29,120	24,187	96,596
GROUP U: SVC			1,500,000	1,500,000
Unassigned			1,500,000	1,500,000
Total	2,498,401	1,029,306	6,490,387	10,018,093
Insurance (3% on CL & CM)				105,831
Contingency (10% on CL & CM)				352,771
Mob/Demob (5% on CL & CM)				176,385
Heated Equip Storage (0.5% on CM & OFM)				37,598
Engineering (12% on CL, CM, & OFM)				1,202,171
Project Management (3% on CL, CM, & OFM)				300,543
Subtotal				12,193,393
Performance Bond				56,000
Total Estimate				12,249,393

Figure 8: Jarvis Creek Substation Budgetary Cost Estimate

4.2 Substation O&M Costs

We estimate the substation O&M costs for the O'Neill, Pump Station 11, Tok and Jarvis Creek stations to average $470k/year total for all four stations. The cost assumed that each station was maintained by the host utility and was based on average maintenance costs provided for the Alaska Intertie substations and CVEA's substation maintenance.

4.3 Communication System Modification Costs

Installation of fiber-optic conductors in one of the shield wires is estimated to cost approximately $3 million, including all design and contingencies. Modification of the auto-scheduling and terminal equipment is estimated at $500,000. The use of existing fiber communications along portions in lieu of installing the shield wire fiber-optics in the line could lower the initial communications investment.

5 Land Cost

The land cost component is an estimate to acquire permits or easements from landowners to design and construct an electrical transmission line from Sutton, Alaska to Glennallen to Tok to Delta Junction. This estimate is based on the best available data to identify parcels and the type of parcel ownership such as private, Native Corporation or government agency over one alignment. The total corridor width is 120 feet. The selected corridor is representative of a potential route suitable for the feasibility assessment of this project. The route used for cost selection in no way indicates a preferred route or probable route for the corridor. If the project moves forward, a route selection study that includes public meetings and input review by state, federal and local agencies and organizations should be used to select a preferred route.

Outside the Matanuska Susitna Borough (MSB) taxing authority, determining an exact parcel count and specific ownership is labor intensive and outside the scope of this project. Some assumptions were made, such as when there is evidence that both the State of Alaska (SOA) and a Native corporation have an interest in a given parcel. In this case, it was presumed that the Native corporation owns the parcel. This presumption of private ownership over state is generally true but detailed parcel by parcel title research was not performed.

Every route will have a unique set of permit requirements, parcels, and ownership. The route selected as a representative corridor for purposes of this feasibility assessment generally avoids Native Allotment parcels and the clusters of private ownership along the highway, but does include six miles along the highway in Tok through dense development. Factors that would skew this land cost estimate for other alignments include the following:

- A change in the quantity of labor-intensive land acquisitions such as the National Park Service, restricted Native Allotments, and Military.
- Poor public relations creating a project-wide animosity.
- Failure to consider eminent domain as a last resort but essential tool for land rights acquisition.
- Significant changes in government agency permitting fees or procedures.
- New laws requiring purchase of more area than is necessary, such as Minnesota's "Buy the Farm" statute.

5.1 Estimated Cost

The estimated cost for land acquisition is roughly $19,000,000. This includes title research to identify parcels and owners, a right of way survey to identify parcel boundaries and draw parcel maps, appraisals, direct compensation to purchase easements and the labor to acquire easements. Permits for the following are included: State of Alaska; Department of Natural Resources and Department of Transportation; Bureau of Land Management; U.S. Military; and the Matanuska Susitna Borough.

5.2 Presumptions & Risk Analysis

Standards and minimum requirements for the appraisal, surveying and acquisition may be dictated by funding sources. It is presumed that land negotiations and appraisals will follow the Uniform Act of 1971. A field survey to determine easement areas is included. Title research is included to determine parcels and parcel ownership.

In addition to standards imposed by funding sources, the desired level of risk also is a factor. The standard of proposed title research stops short of "marketable title," the highest level of title research. A lower standard of title research that is proposed is also possible, and along with that, a higher risk of trespass and legal problems.

The proposed Right of Way survey will not set property corners of the parent parcel or easement corners. It will result in a description that can be staked by a land surveyor.

Appraisals are necessary to comply with the Uniform Act of 1971, but if the funding source does not require that, then a few "typical" appraisals can be obtained and used as a basis of compensation to the landowners. A few eminent domain condemnations are included. Electric transmission lines are among the least popular right of way corridors to purchase. Some landowners will not sign an easement document regardless of the money offered, and it will be necessary to condemn to clear title in some cases. The judicious use of eminent domain, as a last resort, is an essential tool to complete a long right of way corridor.

5.3 Incentive Payments

One approach to purchasing easements is to offer an incentive for signing early (i.e. 90 days from the date of offer). An incentive program increases the direct compensation to the landowners. It often saves money by reducing the labor needed to acquire the easements, while shortening the negotiating time for the average landowner. It also tends to "level the playing field" between the more business savvy and less sophisticated landowners. The Alaska Department of Transportation and Public Facilities (DOT) has employed incentive payments for several road projects by offering a sliding scale of inducement of about 30%.

5.3.1 Recommendations

Right of Way acquisition costs are a small percentage of the cost for a project such as this one, but represents a high risk to the project's timeline, constructability and construction costs. There will always be differences of opinion as to land values, with the ultimate price being one agreed to by the landowner. The costs of offering more than the appraised value has little impact on the overall construction costs but may accelerate land acquisition and mitigate any public opposition to the project.

Adding an incentive payment of 30% of direct easement costs for signing easements promptly will most likely expedite land acquisition and result in some savings in the time and money to negotiate easement purchases.

Follow the *Uniform Relocation Assistance and Real Property Acquisition Act of 1970* in guiding appraisals and acquisitions. If certain federal funding is used for ANY aspect of the project, those funds are in jeopardy if the Uniform Act is not followed. Following the *Uniform Act* also establishes procedures to help the constructing organization to prevail in eminent domain actions.

5.4 Methodology

The Easement-Land cost aspect of the study was a collaboration between Electric Power Systems (EPS) and AHTNA, who providing base mapping and ownership type research to identify the “path of least resistance” for potential routes from a land impact view.

A geo-referenced base map was created to identify existing parcels, with the prime source being Geographic Information System (GIS) files from State of Alaska (SOA), Federal Bureau of Land Management (BLM), and the Matanuska Susitna Borough (MSB). These files reflect initial source creation of parcels such as BLM and SOA patents, but once the patents are issued, that government agency generally stops tracking that piece of land, so more recent transfers or subdivisions of land may not be depicted. There are some parcels created by deed that are not reflected in the GIS files, but as a whole the GIS parcels are adequate to avoid clusters of development and identify Native Allotment parcels which are among the most difficult to obtain easements across. Once an agency transfers ownership to another entity, they stop tracking and updating the GIS files. This can result in overlapping GIS files reflecting different ownership for the same parcel of land. For example, the BLM may issue a patent or tentative approval to the State of Alaska for a parcel, then a Native corporation selects the same parcel, resulting in the State deeding it back to the BLM, who later transfers it to the Native corporation.

The GIS files are not a reliable source to identify ALL private parcels, and research to identify all private parcels outside organized Boroughs is labor intensive. The scope of research did not include identifying every parcel and every or ownership of every parcel, but some additional research was performed to identify parcels not reflected in the GIS database. *BLM Master Title Plats and Patents* were obtained to clarify ownership of GIS files and to provide a basis for the cost estimate.

5.5 Existing Corridors

5.5.1 Highways

The highways are obvious, convenient locations for a transmission line. They offer ease of access to construct and maintain the line, but development along highway corridors typically greatly increases the number of private land holdings requiring acquisition, as well as the number of complaints from landowners and others.

Most of Alaska’s highway rights of way are easement interests, created by Public Land Orders (PLOs). The Alaska Department of Transportation and Public Facilities (DOT) has the ability to permit utilities in their rights of way. In cases where the underlying ownership of the highway ROW is federal, including Native Allotments, then a permit or easement from the underlying fee owner is required in addition to the DOT permit. Generally the DOT forces utilities in the outer 10 feet of the ROW, and it is necessary to obtain an easement outside the ROW for safety clearances, and desirable to obtain a full width ROW (1/2 width outside the ROW) for clearing and maintenance.

5.5.2 Pipelines

It was necessary to move large quantities of fuel to the Fairbanks area during World War II to support military operations in the Alaska interior. The CANOL (Canadian Oil) pipeline was constructed between 1942 and 1944, connecting oilfield in the Canadian Northwest Territories to a refinery in Whitehorse. From there, fuel was passed to Ladd Field, now Ft. Wainwright. The Canadian portion was only in full operation for a year, but the Skagway to Fairbanks line operated for another ten years. Much of the ROW for the pipeline was relinquished in the 1970's.

The Haines-Fairbanks pipeline was an 8-inch diameter pipeline constructed between 1953 to 1955. A 1970 investigation into the deterioration of the pipeline led to closing the Haines to Tok section, and the Tok to Fairbanks section was closed in 1973. Most of this pipeline does not have an easement that remained when the land ownership changed, but was rather a 44LD513 title notation. The duration of a 44LD513 designation is that it cannot be transferred outside of federal ownership, and ceases to exist when the purpose for the reservation ends. These pipeline corridors are not considered available for any future transmission line project.

5.5.3 RCA Easement

"An easement and right-of-way to operate, maintain, repair and patrol an overhead open wire and underground communication line or lines, and appurtenances […]" exists along the Alaska Communication Systems cable, which was conveyed to RCA Alaska Communications, Inc., by easement deed dated January 10, 1971. This easement exists along much of the Glenn and Alaska Highways, and is routinely recognized as an existing encumbrance by the majority of conveyances of private and state properties. Various utilities now hold interest in different segments of the route, but cannot unilaterally expand the type of use to include electric transmission lines. Like many of the early military lines, this line was in a convenient location relative to the road system at the time, and it is a popular location for communication lines along the Glenn and Alaska highways.

5.5.4 Direct Land Costs

This category reflects an estimate on what money would be paid to the landowner for an electrical transmission line easement. Land sales were researched in the project area for the last five years and were used as a basis for a per-acre cost for the easement. Generally, the smaller the parcel, the better the access, and the greater the cost per acre.

5.5.5 Direct Land Costs, Specific Methods

A base map showing parcels was developed to select viable routes. We provided a route generated in AutoCAD and/or PLS-CADD for comment and review of land issues.

Once a feasible route was refined, a GIS program was used to buffer the alignment 60 feet both sides of the centerline. This 120-foot-wide strip was then chopped into shorter strips according to the parcels it crossed by intersecting the buffered strip with the parcel boundaries. Information, including the intersected area and the parent parcel size was extracted and exported to an Excel spreadsheet. Each intersected area is categorized according to the type of owner, centerline length within the parcel along with the area.

Each parcel categorized by ownership, for example, a public ownership such as State of Alaska where no easement would be purchased directly, or a private owner such as an individual or Native entity where an easement would be purchased. Private parcels were further classified according to the size of the parent parcel, and a value per acre applied based on similar sales research.

5.5.6 Indirect Land Costs

Indirect land costs include efforts to survey, map, appraise and acquire easements from private owners, and survey and permitting costs for other types of owners such as the State of Alaska.

The effort to acquire easements through negotiated settlements was made presuming the Uniform Relocation Assistance and Real Property Acquisition Act of 1970 (Uniform Act) will be followed. This sets minimum standards for the appraisal and negotiation process. In the case of some owners such as the State of Alaska, an easement is not directly purchased, but there are other costs associated with obtaining that easement or permit, such as an as-built survey for a DNR permit.

5.5.7 Appraisals

The Uniform Act requires a narrative appraisal to establish Fair Market Value (FMV) as a base line minimum for an offer amount. Certain acquisitions of small size and value can be made with a less expensive appraisal waiver document, but for estimating purposes full appraisals were used for each parcel. If funding sources do not require the Uniform Act to be followed, fewer appraisals will be required for the acquisition.

5.5.8 Private Parcels

Generally, small private parcels were avoided, but there are a number of small private parcels along the highway through the Tok core area that could not be avoided. DOT will generally require transmission lines near the edge of the ROW strip and can deny placing a transmission line inside the ROW if reasonable alternatives are available. Transmission line rights of way along the edge of the highway ROWs increases the chances of impacting private property, but can result in needing only half of the ROW width on private land, which reduces the direct impact to the private parcel.

5.5.9 Mining Claims

Mining claims on state land represent a private interest on SOA owned land. SOA DNR requires a letter of non-objection or similar from the mining interest, so mining claims are counted as private parcels for cost estimation.

5.5.10 Surveying

Right of way surveying and mapping, which accurately related the transmission line to parcel boundaries is required for some aspects, such as perfecting the SOA DNR easement. A DNR-standard as-built survey alone can cost $10,000 per mile depending on the number of survey monuments that need to be found or set.

It is possible to acquire an easement across a parcel with no survey using a “blanket” easement. Blanket easements are more difficult to negotiate. Well-informed landowners realize they can create a cloud on the title of the whole property, and will not sign.

While the GIS lines provide an efficient avenue to planning and estimating, a field survey is necessary to establish good locations. There are several sections in the Tok area where the GIS lines are more than 1/4 mile from the correct positions, and many of the more remote U.S. Surveys GIS lines can be even farther from their actual location on the ground.

The cost of a right of way survey can vary substantially according to the final route location. The use of a helicopter is expensive, but in some remote areas is the most cost-effective method of access. A right of way survey may not be required for all parcels. A high percentage of the route is across SOA managed land, which does require a high-quality survey.

While most of the route crosses large, sometimes un-surveyed territory, there are some “urban” type parcels requiring a more intensive surveying effort to determine boundary lines. The survey cost estimate includes an additive element for these high-density parcel areas.

5.5.11 Government Permits

Permission to build and maintain an electric line across government managed land such as the State of Alaska is in the form of a permit. The application usually includes a Plan of Development which identifies environmental concerns, and how the work methods will address those concerns. It is presumed that the Plan of Development will be created by the environmental contractor. The only permits included in this estimate are the State of Alaska, DNR & DOT, Mat-Su Borough (for their public process for transmission lines), the BLM and the Military.

5.5.12 Eminent Domain--Condemnation

Electric transmission lines are sometimes seen as unpopular improvements due to their impact on the viewshed and a relatively common perception of health hazards related to the close proximity to power lines.

While the use of eminent domain must be used as a last resort under the Uniform Act and cannot be used as an explicit threat, it is a necessary element to complete a long linear project. If a landowner refuses to settle voluntarily and a condemnation is filed with the court, most landowners settle before going to trial. If an impasse is reached and condemnation is not filed and this becomes common knowledge, the number of people refusing to sign often increases dramatically.

Eminent domain also has a leveling effect in situations when some landowners are knowledgeable in business, but other less-knowledgeable landowners face the same objective standards set by the court, which can result in unequal outcomes. Experience shows that the use of eminent domain to clear title can be necessary as some landowners will not sign voluntarily regardless of the compensation offered.

One element of a successful eminent domain exercise is a need and necessity conclusion based on comparing multiple routes, which is beyond the scope of this feasibility study.

5.5.13 Budgetary Land Cost Estimates

5.5.13.1 Regulatory Permitting Costs

Regulatory Permitting								
Landowner Category	Specific Landowner Type	QUANTITY OF PERMITS	Permit Cost, Each	Subtotal Permit Costs	Asbuilt Surveys, Additional to ROW Survey	Number of Parcels	Subtotals	
SOA	DNR	2	$30,000	$60,000	$200,000	84	$260,000	
SOA	DOT	10	$5,000	$50,000	$100,000		$150,000	
USA	BLM	1	$50,000	$50,000	$50,000	None on this alignment	$100,000	
USA	MILITARY	1	$50,000	$50,000	$40,000	3	$90,000	
BOROUGH	MSB	1	$20,000	$20,000	$20,000	1	$40,000	
						88	**$640,000**	**TOTAL**

5.5.13.2 Title & Surveying Costs

Title Research, Right of Way Surveying Costs												
# Survey Monuments (Mons)	# Parcels	Production Rate, Mons/Day to Survey	Crew-Days	Helicopter Crew Days	Driving Crew Days	Crew Wages & Lodging /Day	Helicopter / Day	General ROW Mapping/Mile	Parcel Maps Each	Title Reports & Rural Research, Average / Parcel		
1700	280	6	283	142	142	$4,500	$12,000	$2,500	$2,000	$3,000		
						Crew Wages & Lodging subtotal	Helicopter	General ROW Mapping Subtotal	Parcel Maps	Title Research Total	**Subtotal Rows**	
						$1,275,000	$1,700,000	$1,000,000	$560,000	$840,000	**$5,375,000**	
Additional Urban Area Surveying, 3 Mons/Private Parcel						Additional Crew Wages & Lodging subtotal		Additional Urban / Private Parcel Mapping, $1000/parcel	Urban Area Parcel Maps Addition al Detail			
270	90	6	45	No Heli	All Driving	$202,500	None	$90,000	$90,000		**$382,500**	
											$5,757,500	**TOTAL**

5.5.13.3 Land Acquisition Costs, Summary

Land Acquisition Costs										
Landowner Category	Specific Landowner Type	Number of Parcels	Distinct Parent Parcel Owners	Direct Land Costs	Appraisals ($6000 each)	Negotiation Costs ($10,000 individuals each, $20,000 for Native corporations, $50,000 for Native allotments)	Condemnation to Cure Title Defects & Negotiation Impasses, File in Court, (20 @ $100,000 each)	Condemnation, Trial, (5 @ $300,000 each)	Subtotals	
CITY	Delta Jct	1	1	$5,000	$6,000	$9,000			$20,000	
PRIVATE	PRIVATE	79	79	$514,011	$474,000	$711,000	$2,000,000	$1,500,000	$5,199,011	
PRIVATE	MINING CLAIM	75	17	$609,358	$102,000	$153,000			$864,358	
PRIVATE	AG. LEASE	16	16	$544,111	$96,000	$144,000			$784,111	
PRIVATE	UNIV. OF AK.	0	0			$0			$0	
PRIVATE	MENTAL HEALTH	6	1	$397,089	$36,000	$9,000			$442,089	
PRIVATE	NATIVE VILLAGE	29	9	$4,336,104	$174,000	$180,000			$4,690,104	
PRIVATE	NATIVE REGIONAL	12	3	$487,938	$72,000	$60,000			$619,938	
RESTRICTED	NATIVE ALLOTMENT	1	5	$50,000	$6,000	$50,000			$106,000	
		219	**131**	**$6,943,611**	**$966,000**	**$1,316,000**	**$2,000,000**	**$1,500,000**	**$12,725,611**	**Subtotals**
		(SOA Parcels							**$640,000**	**Regulatory Permitting**
		Not Included)								
									$5,757,500	**Title, Surveying, Appraisals**
									$19,123,111	**TOTAL**

6 Electrical System Studies

6.1 Introduction

This section provides the transmission planning results that highlight necessary hardware and topology changes, power flow analyses, and transient stability analyses. The steady-state power flow results include considerations such as interconnection route/path, line voltage, conductor sizing, line spacing, transformers, reactors, and SVCs. This section also includes the in-depth line compensation and voltage support simulations.

The transient stability (dynamic) work explores the feasibility of the two most-promising designs from the steady-state power flow results. The dynamic simulations were performed on various Railbelt seasonal cases that include all of the additional hardware and interconnections added during the power flow studies. The dynamic simulations also included known critical contingencies (failures of critical power system components) within the Railbelt, as well as new contingencies that become possible with the new Roadbelt Intertie. Remedial Action Schemes (RASs) and dynamic SVC models are evaluated in order to control the transient response for some of the more severe contingencies.

The transmission lines were evaluated using criteria consistent with planning criteria used in the existing Railbelt system to ensure that the CVEA and Tok systems experience the same level of service as the rest of the interconnected system. These criteria are listed below and further defined in following sections.

Steady-State

- Capable of 75 MW of firm transfer from Southcentral AK to Fairbanks
- Capable of 125 MW of non-firm transfer from Southcentral AK to Fairbanks
- Thermal limits of any transmission line impacted by the new line are not exceeded
- Steady-state voltages above 0.98 and below 1.03 on the entire system
- Energization of open lines' voltage profile below 1.05
- Stability
- No contingency results in cascading failures
- No contingency results in loss of synchronism across any transmission line or loss of unit
- At least 75 MW of firm power transfer following any single contingency
- Transient voltage swings must stay above 0.8 pu.

6.2 Topological Overview

The proposed Roadbelt Intertie will provide a second path for power to flow between the Anchorage Bowl area and Fairbanks while simultaneously interconnecting other islanded utilities and municipalities along the way. This will create a transmission corridor electrically parallel to the existing Alaska Intertie which begins at the Douglas substation in MEA, runs north through Healy, and terminates in the GVEA system.

In general, this new interconnection will be a route that begins in the MEA system and interconnects to the CVEA system near Glennallen, continues to the AP&T system in Tok, and terminates in the GVEA system. The relevant mileages between the various substations are shown in Table 4 below. Two slightly different topologies are described in the following subsections that both achieve the described interconnection goals.

Due to the necessity of completing the electrical studies and possible line routings concurrently, there were certain assumptions made for the completion of the electrical studies. Differences between the line routing and configuration used in the electrical studies and the possible routes used in the cost estimating are not significant to the results of the study.

Examples are the line miles between stations and the location of some stations along the route. The representation of Gakona as a bus in the PSS/E model is for electrical modeling only. It does not represent an actual substation at Gakona. Load in Gakona will continue to be served via CVEA's 24.9 kV network from Glennallen. Gakona simply represents a physical location where AK-1 and AK-4 highways diverge, and it serves as a natural physical location in the area where the double circuit in Topology 2 below might diverge.

Table 4: Distance Between Substations

From Substation	To Substation	Miles
O'Neill	Pump 11	130
Pump 11	Gakona	16
Gakona	Tok	120
Tok	Jarvis	110
Pump 11	Tok	136
Gakona	Jarvis	136

6.2.1 Topology 1

The first topology includes the original path as described in the project plan. This path connects each city/area/substation in series beginning in Sutton, following highway AK-1 east to Glennallen, continuing north-east to Tok, then following AK-2 northwest to Delta Junction. A diagram of the connections and substations along this proposed route can be found in Figure 9 below.

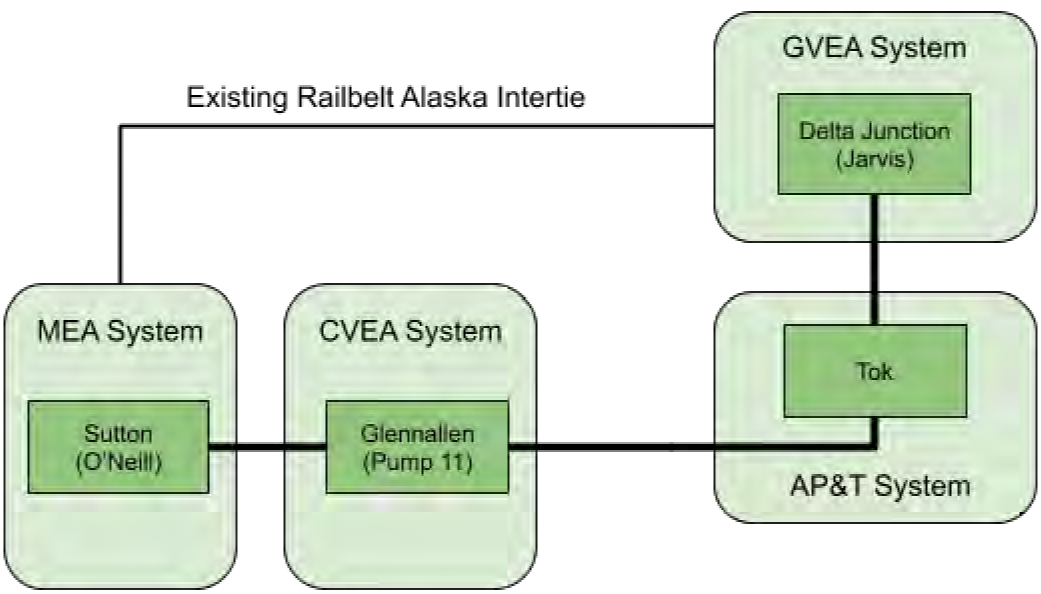


Figure 9: Topology 1 - Transmission Line Path for the Roadbelt Intertie

6.2.2 Topology 2

EPS evaluated an additional topology for consideration as seen in Figure 10 below. This second topology slightly alters the configuration seen in Topology 1 by connecting Tok radially from Pump 11 instead of making a series connection from Glennallen, through Tok, to Delta Junction.

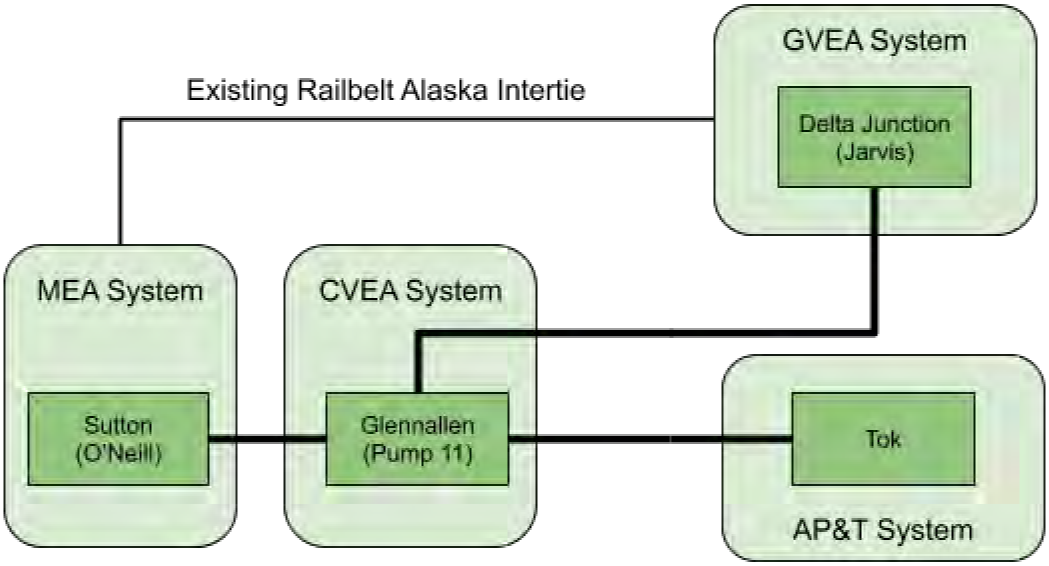


Figure 10: Topology 2 - Transmission Line Path for the Roadbelt Intertie

There are several anticipated advantages to Topology 2. First, the primary transmission path from the Anchorage Bowl to the Fairbanks area is shortened. In effect, the overall impedance of the path that carries the bulk of the power North is decreased. Not only will this decrease the losses, but it will also strengthen the connection between utilities during transient events. This is revisited in the subsections that follow.

Second, the transmission line that connects Tok can be built at a lower kV/MVA rating because it no longer needs to have the capability to carry the bulk of the power flow from South to North, all the way into the GVEA system. The Tok connection will only need to be built to support anticipated load near the Tok area. The costs for this alternative were not evaluated.

6.3 Railbelt PSS/E Model Modifications

Multiple changes to the existing PSS/E Railbelt database were needed in order to simulate the new transmission interconnection. Besides calculating impedances and adding the new transmission lines to the database, EPS also made the following additions/modifications:

1. Expanded O'Neill substation to include a 138 or 230 kV bus with a 75 MVA, 7% impedance transformer that connects to the existing 115 kV system.
2. Incorporated the full CVEA PSS/E model including:
    a. 138 kV and 24.9 kV systems
    b. All major generation sources (Allison Creek Hydro, Solomon Gulch Hydro, Valdez Diesel, and Glennallen Diesel).
    c. Added typical dynamic models, with some standard parameters for Allison Creek Hydro, Solomon Gulch Hydro, Valdez Diesel, and Glennallen Diesel facilities. Where possible,

assumptions were made about the dynamic model parameters according to size, fuel type, and some limited existing parameter data provided by CVEA.

d. Updated system loads and dispatch according to CVEA guidance.

3. In the 230 kV cases, added a new bus at Pump 11 (CVEA) to interconnect CVEA to the rest of the Railbelt. In the 138 kV cases the connection was made at the existing Pump 11 bus.
   a. The 230 kV cases also required a new transformer. Given the need for reactive compensation, this transformer was modeled as 3-winding (230/138/24.9 kV) where the reactive compensation device was attached to the 24.9 kV tertiary winding.
   b. During the transient stability work (See Section 6.5), EPS determined that dynamic models for the SVCs were required. These devices were modeled as a CSSCST standard library model and tuned appropriately for the desired response on the Glennallen – Palmer line section.
   c. The Transformer at Pump 11 was modeled as a 50 MVA transformer with 8% impedance.

4. The Tok system was modeled as a 230 kV bus with a step-down transformer to 24.9 kV. The low side included a single static load at 3 MW. (In the alternate topology case this was a 138 kV bus with step-down transformer to 24.9 kV). Loads at Tok could grow significantly without impacting the study results.
   a. In the Topology 1 configuration there was an SVC modeled on the low side of the transformer to control the 230 kV bus voltage.

5. The GVEA connection was directly interconnected to the existing Jarvis bus in the 138 kV cases, but required an additional bus and transformer in the 230 kV cases.
   a. The 230/138 kV transformer was modeled as a 75 MVA transformer with 7% impedance.
   b. The reactive capability of the existing SVC at Jarvis was modified to provide the necessary compensation based on the charging of the new transmission lines. This was done by adding an appropriately sized fixed reactor to shift the range of the SVC in the reactive direction.

6.4 Steady-State Power Flow Simulations

This section discusses results that were obtained from steady-state power flow simulations. The results were used to determine the viability of both Topology 1 and 2, determine the most reasonable voltage levels and transmission line characteristics, and determine the reactive compensation needed along the new path.

6.4.1 Transmission Line Parameters

EPS evaluated multiple transmission line configurations and options, as shown in Table 5. This initial set of line configurations was chosen based on the following:

1. Mileages as discussed in Table 4 above.
2. The combination of the new line and the existing Anchorage-Fairbanks Intertie should provide 75 MW of firm transmission between Anchorage and Fairbanks.
3. The new line and the existing Anchorage-Fairbanks Intertie should provide 125 MW of total flow northward including firm and non-firm transmission.
4. Existing transmission lines in Alaska use similar construction/sizing.

Table 5: Transmission Line Conductor and kV Configurations

kV	Conductor	Phase to Phase Spacing	GMD	Single or Bundled
138	556.5 ASCR - Dove	18.25'	23	Single
138	795 ASCR - Drake	18.25'	23	Single
230	795 ASCR - Drake	19.5'	24.5	Single
230	795 ASCR - Drake	20.5'	25.8	Double Conductor Bundle (1')
230	954 ASCR - Cardinal	19.5'	24.5	Single
230	954 ASCR - Cardinal	20.5'	25.8	Double Conductor Bundle (1')

The impedance characteristics specific to the mileages in Topology 1 and Topology 2 were calculated for each of the options presented in Table 5. These results are depicted in Table 6.

Table 6: Roadbelt Intertie Line Impedances

138 kV -- 556.5 Dove Single Conductor -- 23' GMD			
470 A -- 112 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.1352	0.5462	0.1306
Pump 11 to Gakona	0.0166	0.0672	0.0161
Gakona to Tok	0.1248	0.5042	0.1205
Tok to Jarvis	0.1144	0.4622	0.1105
Total Series Impedance	0.391	1.5798	0.3777
% of 230kV 795 Sing. Cond	430.1%	282.2%	35.4%

138 kV -- 795 Drake Single Conductor -- 23' GMD			
590 A -- 141 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.0800	0.5322	0.1343
Pump 11 to Gakona	0.0098	0.0655	0.0165
Gakona to Tok	0.0739	0.4912	0.1240
Tok to Jarvis	0.0677	0.4503	0.1137
Total Series Impedance	0.2314	1.5392	0.3885
% of 230kV 795 Sing. Cond	254.6%	274.9%	36.4%

230 kV -- 795 Drake Single Conductor -- 24.5' GMD			
590 A -- 141 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.0314	0.1936	0.3692
Pump 11 to Gakona	0.0039	0.0238	0.0454
Gakona to Tok	0.0290	0.1787	0.3408
Tok to Jarvis	0.0266	0.1638	0.3124
Total Series Impedance	0.0909	0.5599	1.0678
% of 230kV 795 Sing. Cond	N/A	N/A	N/A

230 kV -- 795 Drake Double Conductor Bundle -- 25.8' GMD			
590 A -- 141 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.0157	0.1458	0.4846
Pump 11 to Gakona	0.0020	0.0179	0.0596
Gakona to Tok	0.0145	0.1346	0.4474
Tok to Jarvis	0.0133	0.1234	0.4101
Total Series Impedance	0.0455	0.4218	1.4017
% of 230kV 795 Sing. Cond	50.0%	75.3%	131.3%

230 kV -- 954 Cardinal Single Conductor -- 24.5' GMD			
650 A -- 259 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.0277	0.1913	0.3738
Pump 11 to Gakona	0.0034	0.0235	0.0460
Gakona to Tok	0.0256	0.1766	0.3450
Tok to Jarvis	0.0235	0.1619	0.3163
Total Series Impedance	0.0802	0.5533	1.0811
% of 230kV 795 Sing. Cond	88.2%	98.8%	101.2%

230 kV -- 954 Double Conductor Bundle -- 25.8' GMD			
650 A -- 259 MVA			
Route	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11	0.0139	0.1448	0.4888
Pump 11 to Gakona	0.0017	0.0178	0.0602
Gakona to Tok	0.0128	0.1337	0.4512
Tok to Jarvis	0.0118	0.1226	0.4136
Total Series Impedance	0.0401	0.4189	1.4137
% of 230kV 795 Sing. Cond	44.1%	74.8%	132.4%

230 kV -- 795 Drake Single Conductor -- 24.5' GMD			
590 A -- 141 MVA			
Route (Topology 2)	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11 (230 kV	0.0314	0.1936	0.3692
Pump 11 to Gakona (230 k	0.0039	0.0238	0.0454
Gakona to Jarvis (230 kV)	0.0328	0.2025	0.3862
Total Series Impedance	0.0681	0.4199	0.8008
% of 230kV 795 Sing. Cond	75.0%	75.0%	75.0%
Pump 11 to Tok (138kV)	0.0912	0.5625	0.1390

230 kV -- 954 Double Conductor Bundle -- 25.8' GMD			
590 A -- 141 MVA			
Route (Topology 2)	R (pu)	X (pu)	B (pu)
O'Neill to Pump 11 (230 kV	0.0157	0.1458	0.4846
Pump 11 to Gakona (230 k	0.0020	0.0179	0.0596
Gakona to Jarvis (230 kV)	0.0164	0.1526	0.5070
Total Series Impedance	0.0341	0.3163	1.0513
% of 230kV 795 Sing. Cond	37.5%	56.5%	98.5%
Pump 11 to Tok (138kV)	0.0912	0.5625	0.1390

The values presented in Table 6 yield some immediate results that helped narrow down the transmission line options available.

First, the 138 kV Dove option would be operating at 67% of its conductor rating under normal single line flows, resulting in losses that exceed typical values.

Second, given that the resistance and reactance (R & X) values for 138 kV 795 conductor are about 275% above the rating of the next highest 230 kV 795 conductor option, it was evident that the losses at the 138 kV level would be prohibitive. This was confirmed in the power flow simulations outlined in subsequent subsections below.

Third, the comparison of Topology 1 and Topology 2 230 kV 795 conductor indicates that Topology 2 resulted in 25% lower overall impedance and charging due to the decrease in mileage directly between

Anchorage and Fairbanks. This alternative was not evaluated for line costs but should be evaluated if the project moves forward.

Finally, the double conductor bundle options, while decreasing the overall impedance of the path between Anchorage and Fairbanks, have significant increases in charging (on the order of 30% higher). The reactive charging increase due to bundling is problematic for the system.

6.4.2 Investigation of Losses

EPS developed multiple cases based on the official seasonal Railbelt load cases (Summer Valley [SV], Summer Peak [SP], and Winter Peak [WP]) for various transfer levels between Anchorage and Fairbanks. The core base cases included 20 MW, 50 MW, 70 MW, 75MW, and 125 MW transfers to the north. Appendix B contains the detailed unit commitment and dispatches used in these cases.

The most limiting case, in terms of losses, for the new transmission corridor is the maximum expected firm transfer of 75 MW measured at O'Neill substation (with the Alaska Intertie open). This particular case demonstrates the highest losses that could be expected on the new line (see Table 7).

Table 7: Alaska Intertie Open -- 75 MW Firm Flows on Roadbelt Intertie

Line Configuration	Losses (MW)
Topology 1 -- 138 kV -- 556.5 Single Cond.	17.6
Topology 1 -- 138 kV -- 795 Single Cond.	11.3
Topology 1 -- 230 kV -- 795 Single Cond.	4.7
Topology 1 -- 230 kV -- 795 Double Cond. Bundle	2.4
Topology 1 -- 230 kV -- 954 Single Cond.	4.1
Topology 2 -- 230 kV -- 795 Single Cond.	3.5

As expected, both 138 kV options indicate a prohibitive amount of losses ranging from 15-23% of the transfer. The remaining cases indicate more reasonable amounts of losses. Other criteria such as amount of reactive compensation, physical characteristics, line performance during transient events, and costs were factored into the final selection used for cost estimating and feasibility.

6.4.3 Investigation of Reactive Compensation Requirements

Reactive compensation was needed to develop a cost-effective transmission path between Anchorage and Fairbanks. Line reactors, static VAR compensators, and/or other shunt reactance is typically needed to counteract the added MVAR requirement of a long, high-voltage transmission line.

Depending on the voltage level and the loading on a transmission line, the line either acts as a source or sink of MVARs depending on whether the loading on the line falls above or below its Surge Impedance Loading (SIL). In the case of a 230 kV transmission line, the SIL is about 140 MW. At the max firm flow on the new intertie of 75 MW, there will be significant charging current into the system from the line.

Different scenarios were simulated in order to determine the amount of reactive compensation needed in order to decrease the effects of line charging.

6.4.4 Line Energization

Energization of a parallel transmission path is the worst case for voltage magnitude and voltage angle differences found at any substation along the two parallel paths. EPS studied the power flow conditions that model the energization of either the Roadbelt Intertie or the Alaska Intertie. In each of the cases, one of the two ties is open, and the resulting substation voltages and voltage across the open breaker were evaluated.

6.4.4.1 Line Energization Voltage Magnitude

Large amounts of reactive compensation were needed in order to minimize the voltage drop across any open breaker along a parallel transmission path like the proposed Roadbelt Intertie. The criteria used for the maximum allowable node voltage at the open breaker was 1.05 per unit (PU). EPS studied each breaker position along the new path from O'Neill to Jarvis and obtained the maximum bucking (Voltage lowering) and boosting (voltage raising) needed in order to ensure that the open end of any line remains under 1.05 PU and the voltage across the open breaker is minimized. This defines the amount of reactive compensation needed in order to control the voltage across an open line, right before attempting to close the line. Table 8 highlights the results.

Table 8: Range of Reactive Compensation Required to Energize the Roadbelt Intertie

	O'Neill (MVAR)		Pump 11 (MVAR)		Tok (MVAR)		Jarvis (MVAR)	
	Inductive	Capacitive	Inductive	Capacitive	Inductive	Capacitive	Inductive	Capacitive
No Line Compensation								
Topology 1 -- 230 kV 795 Single Cond.	-75	0 *	-92	0	-77	0	-42	0
Topology 1 -- 230 kV 795 Double Cond.	-93	0 *	-130	0	-123	0	-55	0
Topology 1 -- 230 kV 954 Single Cond.	-75	0 *	-94	0	-78	0	-43	0
Topology 2 -- 230 kV 795 Single Cond.	-75	0 *	-125	0	-3.3	10	-62	7
With 75% Line Compensation								
Topology 1 -- 230 kV 795 Single Cond.	0 **	0**	-15	12	-18	0	-6	0
Topology 1 -- 230 kV 795 Double Cond.	0 **	0**	-23	11	-38	0	-10	19
Topology 1 -- 230 kV 954 Single Cond.	0 **	0**	-15	12	-19	0	-6	0
Topology 2 -- 230 kV 795 Single Cond.	0 **	0**	-22	10	0	4	-18	7
* Voltage at O'Neill was allowed to settle around 1.02 PU instead of adding capacitive compensation to raise the voltage to 1.05 PU.								
** Voltage at O'Neill was between 1.01 and 1.05 resulting in no reactive compensation requirement.								

Table 8 includes cases with 75% fixed line compensation (bottom half of the table). This means that charging due to the line capacitance was counteracted by adding a fixed line reactor to both ends of each long line section with a total reactance equal to 75% of the line's charging. The only line that does not include fixed line reactors is between Pump 11 and Gakona since the charging due to this short line is negligible.

6.4.4.2 Line Energization Voltage Angle Analysis

One of the other main considerations when studying the energization of parallel transmission paths is the voltage angle across an open breaker. Since Anchorage and Fairbanks are still interconnected via the Alaska Intertie (with the new Roadbelt Intertie open), attention must be focused to the angular difference between the two regions. Table 9 below shows results for three different tie flows.

Table 9: Range of Angular Differences Across Open Breakers During Energization

AK Intertie Flow	Min. Angle	Max Angle
69 - 73 MW	40°	45°
48 - 52 MW	28°	32°
17 - 21 MW	11°	15°

As anticipated, higher initial flows along the Alaska Intertie result in greater angular difference. In other systems an angle of 30 degrees is acceptable for closing the open breaker and that criteria was used in this study. Final criteria will need to be established for the acceptable range in angle difference across the open breaker. In order to reduce the open breaker angle, either the transfer along the closed path needs to be reduced, or supplemental control such as a phase shifting transformer would be required along either the Alaska Intertie or along the Roadbelt Intertie. A phase-shifting transformer was not included in the conceptual design for the system as operational changes can easily change the phase angle to allow for breaker closing.

6.4.5 Both Lines Energized

Although the limiting case for determining the amount of required reactive compensation is the energization case highlighted in the previous section, analysis was done for the amount of reactive compensation needed during normal operation when the Roadbelt Intertie is energized. This provides the range of additional reactive compensation needed during different seasonal load cases, as well as during different northbound MW transfer levels.

The bus voltage target for this set of "normal operation" cases was 1.02 PU along the Roadbelt transmission corridor. The results are shown in Table 10 below where negative values indicate bucking MVARs (inductive compensation) and positive values indicate boosting MVARs (capacitive compensation).

Table 10: Reactive Compensation to hold 1.02 PU voltage at various MW flow levels.

Case	MW Flow Level	O'Neill (MVAR)	Pump 11 (MVAR)	Tok (MVAR)	Jarvis (MVAR)
No Line Compensation					
Topology 1 -- 230 kV 795 Single Cond.	20	-9.9	-35.5	-35.9	-16.3
	50	-9.1	-34.2	-35.0	-15.2
	70	-4.6	-25.4	-33.9	-11.3
	75*	9.0	-16.7	-26.5	-0.5
	125	2.6	-20.6	-29.8	-5.2
Topology 1 -- 230 kV 795 Double Cond.	20	-21.4	-51.9	-48.5	-23.3
	50	-19.1	-50.8	-47.7	-23.1
	70	-13.5	-39.4	-46.7	-19.8
	75*	1.7	-32.8	-41.0	-12.1
	125	-3.8	-35.2	-43.1	-14.9
Topology 1 -- 230 kV 954 Single Cond.	20	-9.9	-34.3	-36.5	-16.8
	50	-8.6	-34.9	-35.6	-16.0
	70	-3.8	-26.0	-34.5	-12.2
	75*	11.1	-17.4	-27.1	-2.1
	125	4.1	-21.3	-30.5	-6.7
Topology 2 -- 230 kV 795 Single Cond.	20	-9.9	-51.0	-0.4	-24.0
	50	-8.9	-49.5	-0.5	-22.5
	70	-4.2	-33.0	-8.1	-18.1
	75*	9.0	-23.2	-9.4	-6.0
	125	4.1	-26.6	-8.9	-10.1
With 75% Fixed Line Compensation					
Topology 1 -- 230 kV 795 Single Cond.	20	-6.4	-5.8	-8.1	-7.3
	50	-5.7	-4.7	-7.3	-6.1
	70	-1.4	0.9	-6.3	-2.1
	75*	40.7	8.8	0.7	15.0
	125	34.2	5.3	-2.4	10.2
Topology 1 -- 230 kV 795 Double Cond.	20	-8.2	-10.3	-11.2	-9.6
	50	-6.0	-9.4	-10.5	-9.3
	70	-0.5	-3.5	-9.6	-5.9
	75*	43.2	2.3	-4.4	8.0
	125	37.7	0.2	-6.3	5.1
Topology 1 -- 230 kV 954 Single Cond.	20	-6.0	-6.0	-8.3	-7.5
	50	-4.9	-4.9	-7.5	-6.6
	70	-0.2	0.7	-6.5	-2.8
	75*	43.2	8.4	0.4	13.5
	125	36.2	5.0	-2.7	8.9
Topology 2 -- 230 kV 795 Single Cond.	20	-6.3	-10.4	1.7	-9.4
	50	-5.5	-9.1	1.6	-7.8
	70	-0.9	3.1	-5.7	-3.3
	75*	40.6	11.7	-7.0	15.2
	125	35.8	8.7	-6.5	11.0
* The existing Alaska Intertie is open in these cases.					

In Table 10 above, the results indicate that the double conductor bundle cases typically require about 1.5 to 2 times the amount of reactive compensation compared to the single conductor cases. Additionally, the single conductor 795 and 954 cases are very similar in terms of the reactive compensation needed. Topology 2 does require a higher concentration of compensation needed at Pump 11 and Jarvis substations, but overall indicates less compensation needed.

When the fixed 75% line reactors were evaluated, the amount of additional compensation went down significantly. The one set of outliers in these cases are the two high-flow cases (75 MW on the Roadbelt Intertie only, and 125 MW flow case that is split between the Alaska Intertie and the Roadbelt Intertie). The high amounts of charging needed in these cases is due to holding the voltages to 1.02 PU. The 795 Drake conductor cases were re-run with more relaxed voltage constraints allowing bus voltages to range between 1.03 PU and 0.98 PU. These cases resulted in a better relationship between node voltage and the variable compensation needed in addition to the fixed line reactors. The results for various flow levels are presented in Table 11 below.

Table 11: Reactive Compensation at Pump 11 & Jarvis with 75% Line Compensation

	MW Flows	Reactive Compensation		Voltages			
		Pump 11 (MVAR)	Jarvis (MVAR)	O'Neill (PU)	Pump 11 (PU)	Tok (PU)	Jarvis (PU)
Topology 1 -- 230 kV 795 Single Cond.	20	-7.5	-10.4	1.027	1.030	1.038	1.030
	50	-5.9	-8.6	1.027	1.030	1.036	1.030
	70	-0.5	-2.8	1.023	1.027	1.035	1.030
	75*	5	9.4	0.985	0.980	0.980	0.985
	125	1.6	0.3	0.993	0.990	0.992	0.990
Topology 2 -- 230 kV 795 Single Cond.	20	-6.5	-6.6	1.027	1.030	1.018	1.030
	50	-5.2	-5	1.027	1.030	1.020	1.030
	70	-1.6	-0.5	1.023	1.027	1.046	1.028
	75*	1.1	5.3	0.985	0.980	1.007	0.980
	125	0.1	0.3	0.991	0.989	1.014	0.987
* The Existing Alaska Intertie is open in these cases.							

The power flow results in Table 11 indicate that no variable compensation is needed at O'Neill or Tok in order to satisfy these relaxed voltage conditions. Pump 11 and Jarvis substations provide the best location for compensation, resulting in the most effective minimal installation of variable reactive compensation for both Topology 1 and Topology 2.

6.4.6 Summary of Power Flow Findings

1. The amount of losses at 138 kV are prohibitive. Any of the 230 kV options provide MW loss ranges that are acceptable.

2. Topology 2 has lower overall impedance between the Fairbanks and Anchorage areas. This topology will likely provide the best MW and MVAR efficiency. The entire path can be built with single conductor construction and still obtain low line losses.

3. The power flow results indicate that the top two designs both use single conductor 795 ACSR Drake at 230 kV. 954 Rail conductor was also evaluated and offers some loss advantages, however, for this study, 795 Drake was used in the final studies. Both Topology 1 and Topology 2 are viable, though stability simulations were run to determine whether additional RAS measures or reactive compensation is needed during critical contingencies.

4. In both topologies, reactive compensation is needed at Pump 11 and Jarvis – though the amount of compensation is slightly higher in the case of Topology 1. In both cases line reactors help to minimize the range of variable reactive compensation needed.

    a. Without line reactors, the energization of the Roadbelt Intertie will require significant variable compensation – on the order of 40 to 130 MVARs at each of the four substations.

    b. Alternatively, with 75% fixed line reactor compensation, the power flow results indicate that variable SVC reactive compensation between -20 and +20 MVARs at both Pump 11 and Jarvis would suffice for maintaining voltage within a tolerable range.

5. Given the large range of variable reactive compensation noted in point 4a above, EPS recommends 75% line compensation on the longer transmission line segments of the new intertie. The following table (Table 12) details the specific line reactor MVAR sizing of the final 2 feasibility options.

Table 12: Recommended Line Reactor Sizing

	Line Segment	Reactor Size at each Terminal (MVAR)	Total Reactive Line Compensation (MVAR)
Topology 1 -- 230 kV 795 Single Cond.	O'Neill to Pump 11	13.8	27.6
	Gakona to Tok	12.8	25.6
	Tok to Jarvis	11.7	23.5
	TOTAL		76.7
Topology 2 -- 230 kV 795 Single Cond.	O'Neill to Pump 11	13.8	27.6
	Gakona to Jarvis	14.5	29
	Pump 11 to Tok (Radial Line)	5	10
	TOTAL		66.6

6. The existing Jarvis SVC already provides a range of -8 to +45 MVARs. Given the initial approximation of -20 to +20 of variable compensation at Jarvis, this existing SVC should suffice, if the overall reactive compensation is shifted toward the inductive side (i.e. adding a fixed reactor of about -18 MVARs would shift the SVC range such that it operates between -26 and +27 MVARs).

7. During energization, a large voltage angle across the open breaker can occur at high flow levels along the opposite path. If an angle criterion of 30 degrees is selected, then the maximum allowable flow on the in-service intertie (e.g. the Alaska Intertie) will be about 50 MW when trying to energize one of the interties. A phase shifting transformer would be able to improve this transfer limit during energization.

6.5 Transient Stability Analyses

The results from the steady-state power flows discussed above indicate that two different configurations are suitable for a new Roadbelt Intertie between MEA and GVEA while simultaneously interconnecting both CVEA and AP&T to the Railbelt system. The two designs that were studied further with transient stability simulations are:

1. Topology 1 – all construction at 230 kV – single conductor 795 ACSR (Drake).

2. Topology 2 – Sutton to Glennallen to Delta Junction constructed at 230 kV with an additional radial line from Glennallen to Tok constructed at 138 kV. All using single conductor 795 ACSR (Drake).

The steady-state power flow simulations confirmed that line reactors are needed along with at least 20 MVARs of variable reactor support at multiple locations along the new intertie. The power flow energization simulations only provide the minimum (maximum negative) reactor sizing, and do not address the worst-case condition for sizing in the positive (capacitive) direction. EPS conducted transient stability simulations to determine the amount of boosting reactive support needed to prevent instabilities and low voltage conditions during contingencies.

Based on our experience, certain contingencies are well known for creating stability problems within the Railbelt transmission system. Taking into consideration these known contingencies as well as issues that could arise by adding a parallel North-South interconnection between GVEA and MEA, EPS developed the following set of contingencies to study (Table 13):

Table 13: List of Transient Stability Contingencies Studied

Contingency #	Type	Location	Note
1	3-Phase Line Fault (4 Cycle)	230 kV -- O'Neill to Pump 11	Roadbelt Intertie (South)
2	3-Phase Line Fault (4 Cycle)	230 kV -- Pump 11 to Gakona	Roadbelt Intertie (Middle)
3	3-Phase Line Fault (4 Cycle)	230 kV -- Jarvis to Gakona	Roadbelt Intertie (North)
4	3-Phase Line Fault (4 Cycle)	203/138 kV -- Tok to Pump 11	Roadbelt Intertie (Middle/Radial)
5	3-Phase Line Fault (5 Cycle)	138 kV -- Teeland to Douglas	Alaska Intertie (South)
6	3-Phase Line Fault (5 Cycle)	138 kV -- Goldhill to Ester	Near Alaska Intertie (North)
7	3-Phase Line Fault (4 Cycle)	230 kV -- Teeland to Pt. Mackenzie	Known Problematic Fault Critical Path in CEA/MEA
8	3-Phase Line Fault (4 Cycle)	230 kV -- West Trm. to East Trm.	Known Problematic Fault Undersea Cable -- CEA
9	Unit Trip	Healy CC #2	GVEA Unit
10	Unit Trip	Beluga Unit 5	Large Anchorage Bowl Unit (CEA)
11	Unit Trip	Entire North Pole Combine Cycle Plant	Large GVEA facility near North end of new Intertie

Each contingency listed was simulated in conjunction with each of the applicable cases defined in Appendix B. Cases 1-8 represent Topology 2 with various seasonal load scenarios and intertie flows; and Cases 9-16 represent Topology 1 with the same seasonal loading and intertie flows.

The official Railbelt PSS/E database includes three seasonal load conditions, namely Summer Valley (SV), Summer Peak (SP), and Winter Peak (WP). These represent the maximum and minimum load conditions experienced seasonally in Alaska as well as changes in line and unit ratings based on the temperature extremes.

The Northern intertie flows range from 20 MW up to 125 MW. According to the specifications of the project, the new Roadbelt line is anticipated to increase the maximum northbound transfer from about 60-75 MW of non-firm energy (on the existing Alaska Intertie) to at least 75 MW of firm energy and an additional 50 MW of non-firm energy (shared between the existing Alaska Intertie and the proposed Roadbelt Intertie). Besides increasing total transfer capacity, one primary goal of the new line is to create a firm 75 MW transfer capacity from the Anchorage Bowl region to Fairbanks. This firm capacity is anticipated to provide various economic and operational benefits to all utilities involved, helping to increase efficiencies and pass along savings to rate-payers.

6.5.1 Initial Stability Results

The first transient stability simulations did not involve any RASs or dynamic SVC devices. The initial set of results reflect the natural response of the Railbelt system to the contingencies in Table 13. A table of the results for Topology 1 can be found in Table 14.

Table 14: Topology 1 Transient Stability Results -- No RAS, No SVCs

	Case #	9	10	11	12	13	14	15	16
	Transfer	20 MW	50 MW	70 MW	75 MW -- AK Intertie Open	125 MW	70 MW	75 MW -- AK Intertie Open	125 MW
	Season	SV	SV	SP	SP	SP	WP	WP	WP
#	Contingency								
1	230 kV Line Fault -- O'Neill to Pump 11					Out of Step			Out of Step
2	230 kV Line Fault -- Pump 11 to Gakona					Out of Step			Out of Step
3	230 kV Line Fault -- Gakona to Tok					Out of Step			Out of Step
4	230 kV Line Fault -- Tok to Jarvis					Out of Step			Out of Step
5	138 kV Line Fault -- Teeland to Douglas			Poor Voltage Recovery	Poor Voltage Recovery	Out of Step	Poor Voltage Recovery	Poor Voltage Recovery	Out of Step
6	138 kV Line Fault -- Goldhill to Ester								
7	230 kV Line Fault -- Teeland to Pt. Mackenzie				Poor Voltage Recovery	Poor Voltage Recovery		Poor Voltage Recovery	Poor Voltage Recovery
8	230 kV Line Fault-- West Trm. to East Trm.				Poor Voltage Recovery			Poor Voltage Recovery	
9	Healy CC #2 Trip							Out of Step	
10	Beluga Unit 5 Trip								
11	Entire North Pole Combine Cycle Plant Trip				Out of Step			Out of Step	

As seen in the table, the majority of cases result in a stable system that does not experience any transient stability issues. All contingencies run in the summer valley season do not have a problem. The loss of Beluga Unit 5 does not result in any issues, and faults between Goldhill and Ester do not have any significant issues.

The results do indicate that faults along the new Roadbelt Intertie, faults that trip the Alaska Intertie, and losses of generation in GVEA can cause out-of-step conditions that separate the north from the south and result in severe voltage issues, significant load shedding, and ultimate system collapse.

In addition, due to the lack of dynamic SVC support along the new Roadbelt corridor, some of the contingencies exhibit poor voltage recovery. EPS flagged various simulation results that indicated voltage recovery that was prolonged (> 0.5 seconds), had significant voltage oscillation (poorly damped swings between north and south), and/or had post-fault voltage dips below 0.8 PU. A couple of examples of poor voltage response can be found below in subsection 6.5.2.

A similar table for Topology 2 can be found below (Table 15) depicting the transient stability results without any additional controls, RASs, or SVCs.

Table 15: Topology 2 Transient Stability Results -- No RAS, No SVCs

	Case #	1	2	3	4	5	6	7	8
	Transfer	20 MW	50 MW	70 MW	75 MW -- AK Intertie Open	125 MW	70 MW	75 MW -- AK Intertie Open	125 MW
	Season	SV	SV	SP	SP	SP	WP	WP	WP
#	Contingency								
1	230 kV Line Fault -- O'Neill to Pump 11					Out of Step			Out of Step
2	230 kV Line Fault -- Pump 11 to Gakona					Out of Step			Out of Step
3	230 kV Line Fault -- Jarvis to Gakona					Out of Step			Out of Step
4	230 kV Line Fault -- Tok to Pump 11								
5	138 kV Line Fault -- Teeland to Douglas				Poor Voltage Recovery	Out of Step	Poor Voltage Recovery	Poor Voltage Recovery	Out of Step
6	138 kV Line Fault -- Goldhill to Ester							Poor Voltage Recovery	
7	230 kV Line Fault -- Teeland to Pt. Mackenzie				Poor Voltage Recovery	Poor Voltage Recovery		Poor Voltage Recovery	Poor Voltage Recovery
8	230 kV Line Fault-- West Trm. to East Trm.				Poor Voltage Recovery			Poor Voltage Recovery	
9	Healy CC #2 Trip							Poor Voltage Recovery	
10	Beluga Unit 5 Trip								
11	Entire North Pole Combine Cycle Plant Trip				Poor Voltage Recovery			Out of Step	

6.5.2 Example of Poor Transient Stability Response – Voltage Issues

Besides indicating failed simulations due to out-of-step trips, the results in Tables 14 and 15 also indicate some simulations that had "poor voltage recovery." As explained, EPS identified those contingencies and cases that had voltage profiles with extended recovery times (> 0.5 sec of depressed voltages), those voltage profiles that had extensive oscillation between the north and south, as well as any post-fault voltage dips below 0.8 PU.

Figures 11 through 13 depict some examples of poor voltage responses that were vastly improved by the addition of SVCs as discussed later in Section 6.5.5.

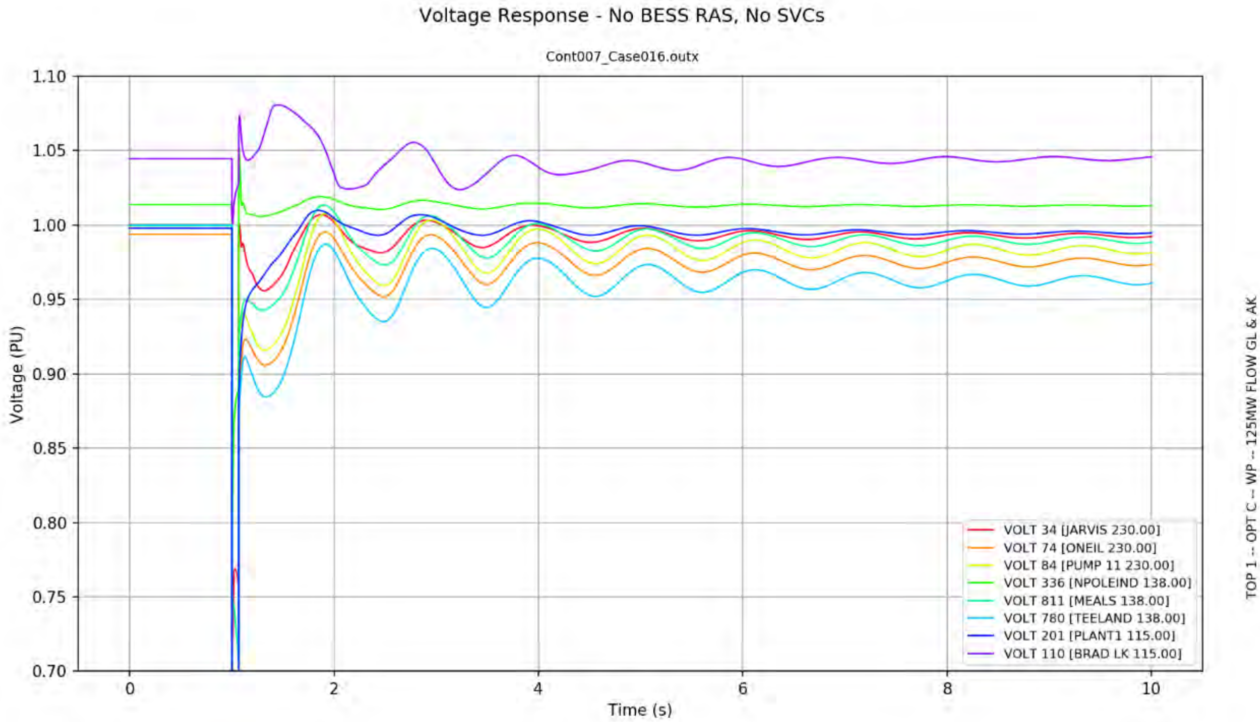


Figure 11: Teeland to Pt. McKenzie Fault - WP 125 MW Transfers - Voltage Oscillations

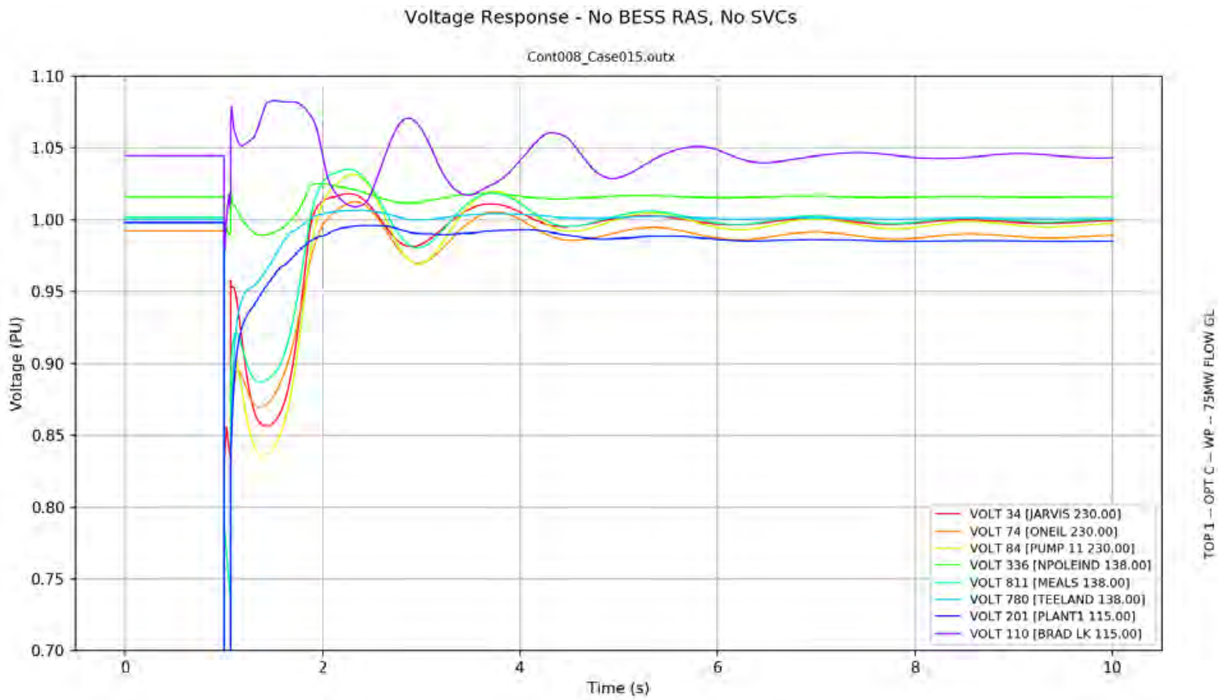


Figure 12: 230 kV Undersea Cable Fault - WP 75 MW Transfer via Roadbelt Intertie 1 second prolonged voltage dip

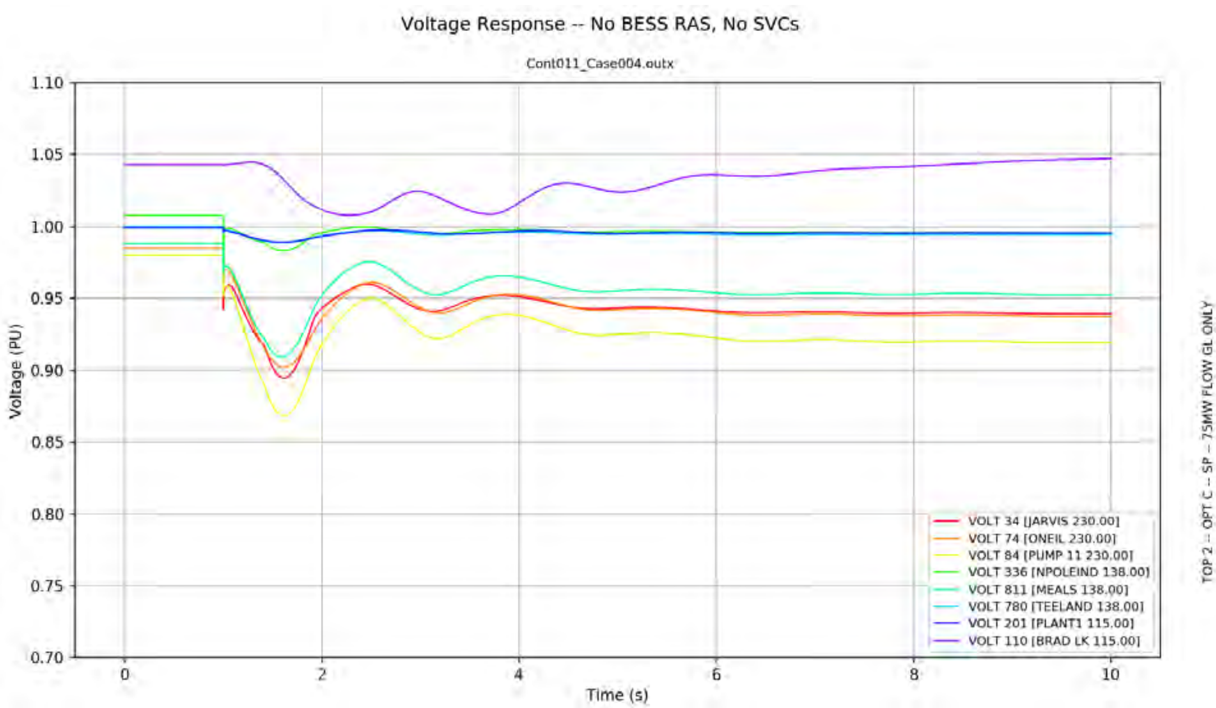


Figure 13: North Pole Plant Trip – Summer Peak 75 MW Transfer on Roadbelt Intertie – Depressed Voltage along Glennallen Corridor.

6.5.3 Implementation of RASs and SVCs

In order to mitigate the instability or poor response in some of the cases highlighted above, EPS implemented both auto-scheduling of the Wilson Battery Energy Storage System (BESS) in GVEA as a RAS, as well as dynamically tuned SVCs at various points along the Roadbelt Intertie.

Auto-scheduling the Wilson BESS as a RAS is something that the Railbelt already uses during severe faults that cause trips of the Alaska Intertie. This means that additional logic & relay communications would need to be added for faults along the new Roadbelt Intertie, as well as for some larger GVEA unit trips. This is a feasible RAS that mitigates some of the more severe responses seen in Tables 14 and 15.

The substation placement and sizing of the SVCs for voltage support were informed by the original power flow results presented in Section 6.4, as well as iterative transient stability simulations to obtain the best MVAR and voltage response.

6.5.4 Wilson ESS Auto-Scheduling – RAS Implementation

In order to mitigate the out-of-step trips seen in the results above, EPS initiated auto-scheduling of the Wilson BESS to 100% output (40 MW) for all of the contingencies that indicated out-of-step or severe voltage dip issues in both Topology 1 and 2. The most severe contingencies were those that went out-of-step, the worst being Contingency 5 (fault and trip Teeland to Douglas - Alaska Intertie Trip) in the Winter Peak 125 MW transfer cases (Cases 8 and 16).

The BESS was auto-scheduled to ramp to 100% output 3 cycles after the fault was detected by the relay (in this case, 2 cycles before the 5-cycle fault is cleared). With the BESS set to full output, Topology 1 still results in an out-of-step condition, meaning additional controls or RASs are needed. However, Topology 2 does result in a stable condition, and is depicted in Figures 14 and 15 below. Note the vast improvement over the out-of-step trip that occurs with no RAS in place.

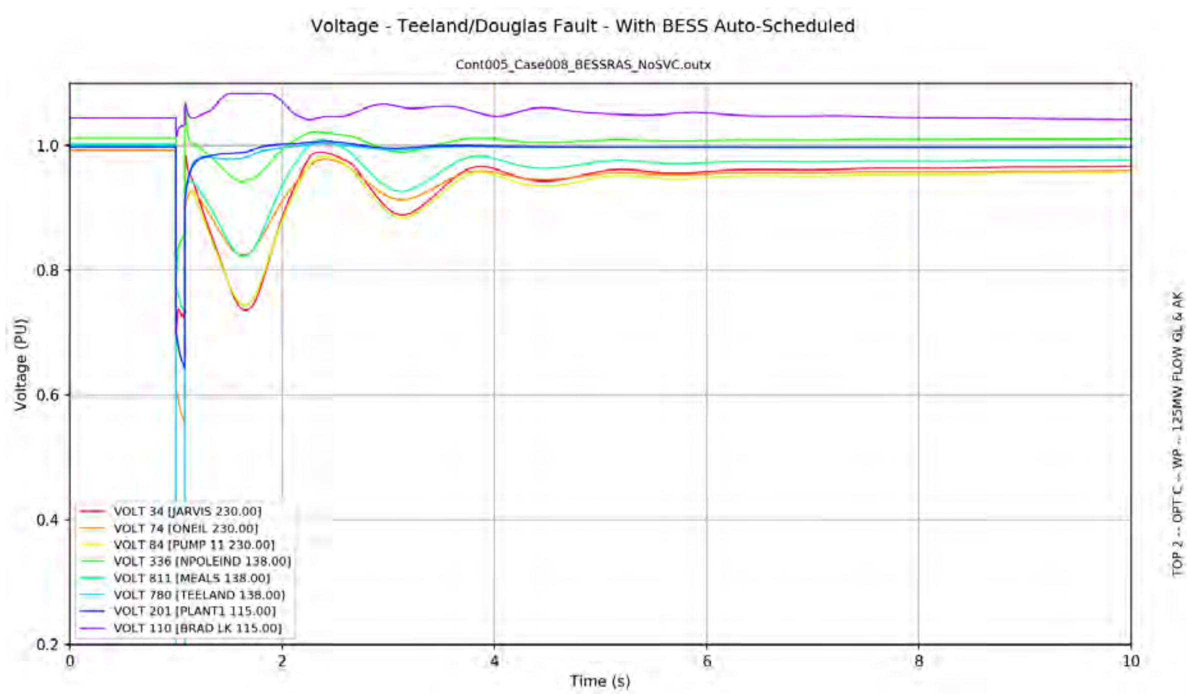


Figure 14: Topology 2 Voltage Response during AK Fault and Trip – BESS RAS Only

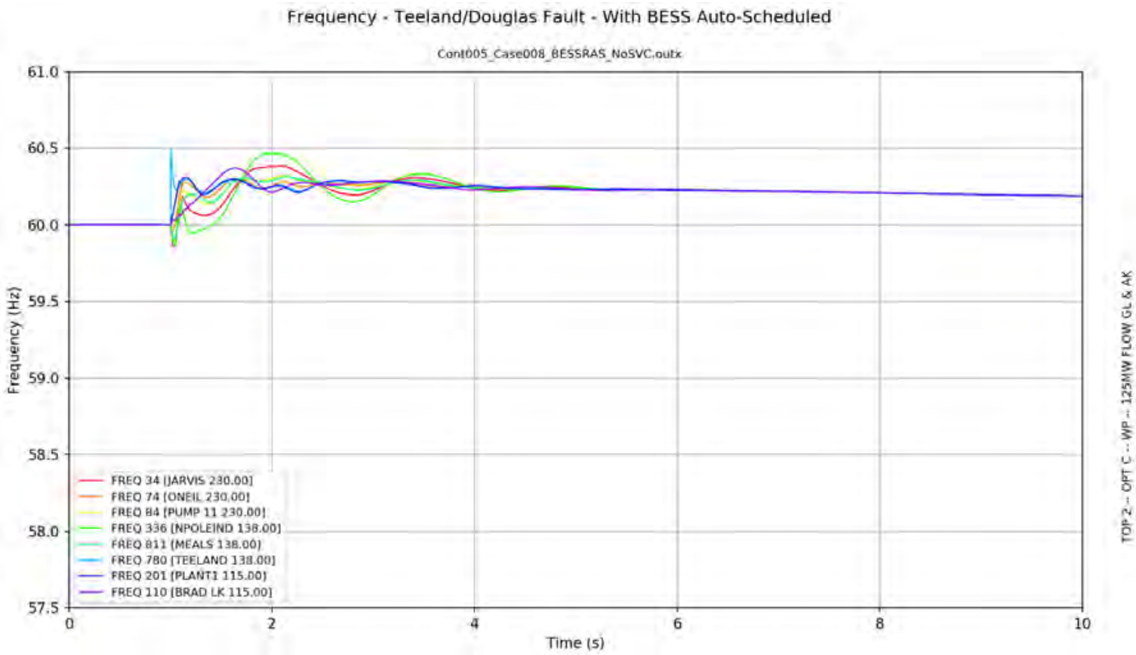


Figure 15: Topology 2 Frequency Response during AK Fault and Trip -- BESS RAS Only

Although the simulation results above indicate that Topology 2 is stable, the voltage profile in Figure 14 does not meet the desired post-fault recovery voltage. Coupled with the fact that Topology 1 still experiences out-of-step conditions in this scenario, this low post-fault voltage dip indicates that the Roadbelt Intertie needs further voltage support between Sutton and Delta Junction – namely SVCs need to be placed strategically along the new path.

6.5.5 Adding SVCs along the Roadbelt Intertie

While studying the various transient stability simulation responses, it became evident that Topology 1 is generally less stable and more prone to collapse without additional fast reactive support provided by SVCs, and Topology 2 in some cases (one of which is highlighted in Section 6.5.2 above) still experiences severely depressed post-fault voltage profiles.

Therefore, additional SVC support is needed at one or more points along the new transmission line path between Sutton and Delta Junction. A set of suitable configurations were determined for each of the two topologies:

Topology 1:

- New Pump 11 SVC: -20 MVAR to +40 MVAR
- New Tok SVC: -20 MVAR to +30 MVAR
- Existing Jarvis SVC: -8 MVAR to +45 MVAR
    - With a -18 MVAR Fixed Reactor

Topology 2:

- New Pump 11 SVC: -20 MVAR to +30 MVAR
- Existing Jarvis SVC: -8 MVAR to +45 MVAR
    - With a -18 MVAR Fixed Reactor

The voltage and frequency response for both topologies are depicted below for the worst performing contingency: Contingency 5, Cases 8 and 16 (Alaska Intertie Fault and Trip, during Winter Peak 125 MW Transfer conditions). These results show that this contingency and loading scenario are survivable and within acceptable frequency and voltage tolerances as long as the Wilson BESS RAS and SVC voltage support are in place as described above.

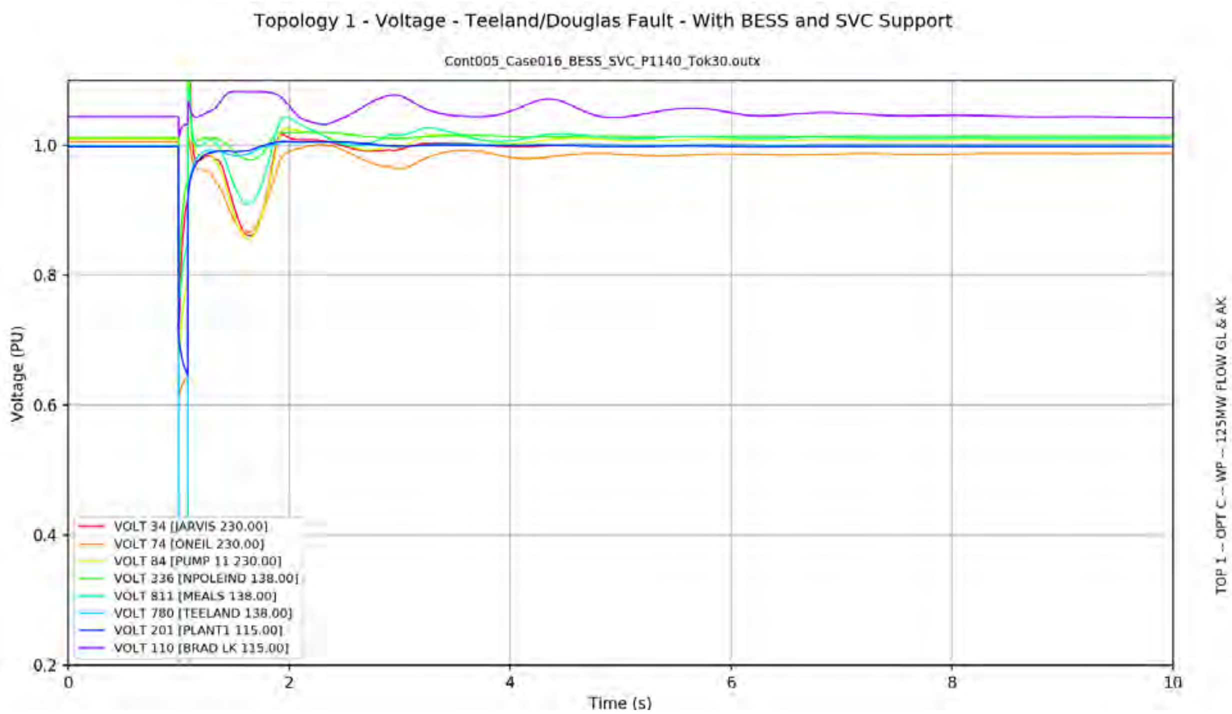


Figure 16: Topology 1 Voltage Response -- AK Intertie Fault -- with BESS RAS and SVCs

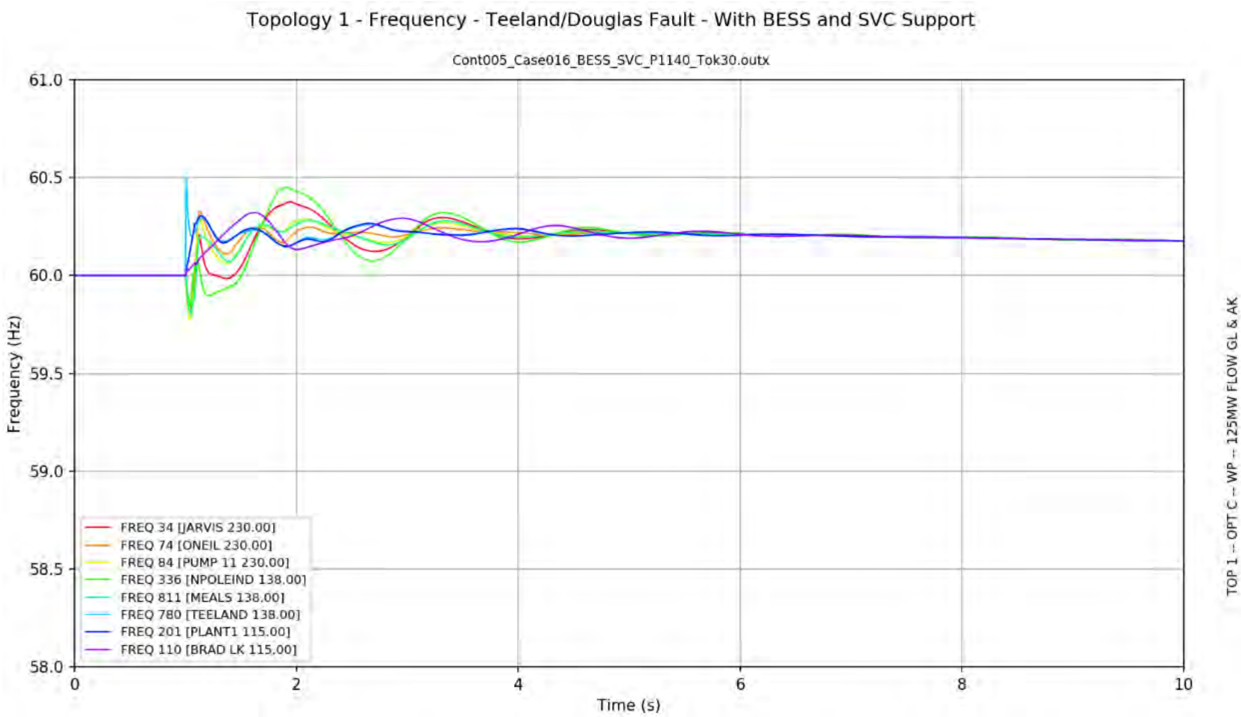


Figure 17: Topology 1 Freq. Response -- AK Intertie Fault -- with BESS RAS and SVCs

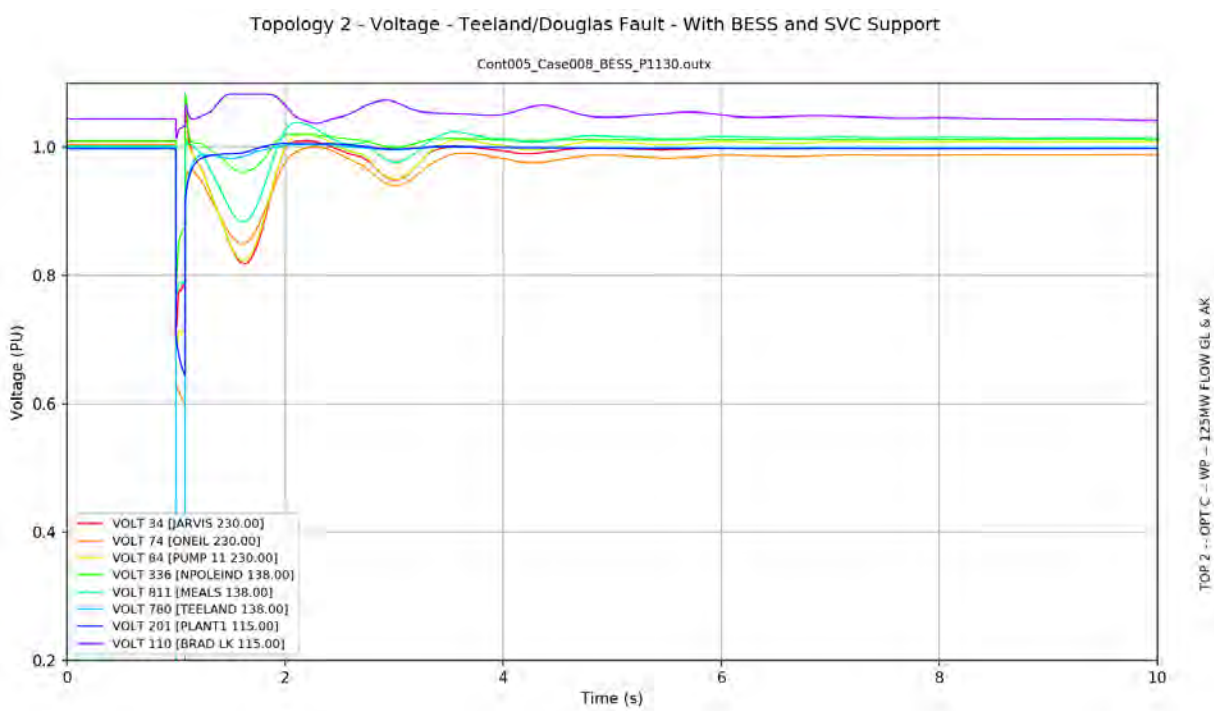


Figure 18: Topology 2 Voltage Response -- AK Intertie Fault -- with BESS RAS and SVCs

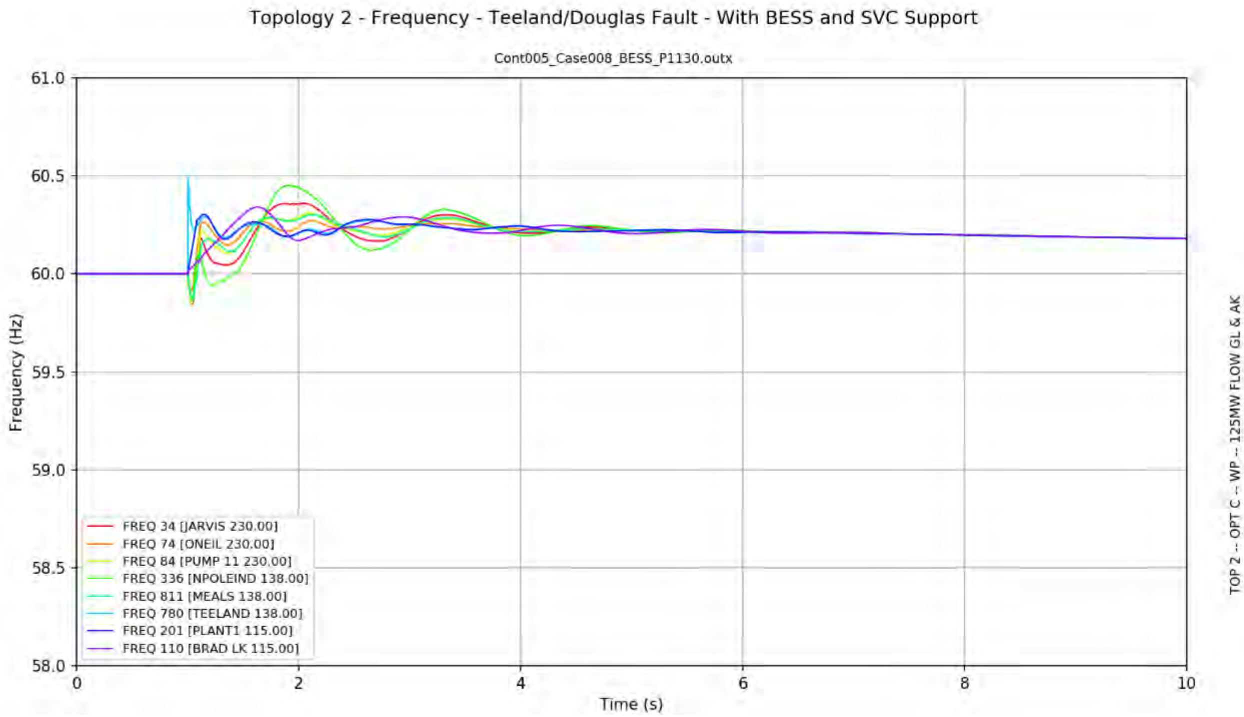


Figure 19: Topology 2 Freq. Response -- AK Intertie Fault -- with BESS RAS and SVCs

With the SVCs in place, all of the simulations that had poor voltage performance or out-of-step contingencies highlighted in Tables 14 and 15 above were resolved (Figures 16-19). With a combination of BESS support following certain contingencies, and dynamically tuned SVCs placed along the new Roadbelt corridor, both Topology 1 and Topology 2 are feasible alternatives for achieving a second intertie between the Anchorage Bowl and Fairbanks.

6.6 System Study Conclusions

The Roadbelt Intertie feasibility study involved significant modifications to the existing Railbelt database, power flow simulations, and transient stability simulations.

Power flows were evaluated for various transmission line designs, energization, interconnecting new areas/utilities to the Railbelt, and steady-state voltage control along the new transmission path.

Transient stability simulations were conducted to evaluate the performance of the Railbelt and new Roadbelt Intertie during different contingency situations and under various seasonal loading scenarios. The contingencies included new faults and trips that are a result of creating a second parallel transmission path between Anchorage and Fairbanks, as well as well-known contingencies in the Railbelt that can cause instability.

The recommendations of this interconnection study are summarized below:

1. Both Topology 1 and Topology 2 are feasible – though increases in SVC size and placement are required for Topology 1 due to the higher overall line length and impedance between Anchorage

and Fairbanks. Topology 2 also has a radial component from Pump 11 to Tok that can be built at 138 kV which should decrease the cost of this option over Topology 1.

2. 230 kV construction with single conductor 795 ACSR Drake or 954 Rail is the recommended transmission line design – this option best balances ampacity / MVA rating, overall impedance between Anchorage and Fairbanks, losses, and amount of reactive support needed. The 795 alternative was used for the final studies and cost estimates, however the final conductor selection should be made during project design.

3. EPS evaluated a new parallel 115 kV transmission line between the interconnection point at O'Neill and the existing connection at O'Neill tap. Through power flow and transient stability simulations, it appears that this additional line is not needed. However, in order to decrease the likelihood of MEA faults interrupting the Roadbelt Intertie, EPS recommends upgrading the O'Neill tap to be a full substation by adding breakers and protection equipment. Doing so will provide additional reliability and robustness to the new Roadbelt Intertie.

4. Due to the length of the line segments and the charging introduced by the proposed line design, line reactors are needed along the new Roadbelt transmission path. EPS proposes that 75% line compensation is sufficient. The line reactor sizes used int h studies and cost estimates are listed below:

Table 16: Recommended Line Reactor Sizing

<table>
<tr><th></th><th>Line Segment</th><th>Reactor Size at each Terminal (MVAR)</th><th>Total Reactive Line Compensation (MVAR)</th></tr>
<tr><td rowspan="4">Topology 1 -- 230 kV 795 Single Cond.</td><td>O'Neill to Pump 11</td><td>13.8</td><td>27.6</td></tr>
<tr><td>Gakona to Tok</td><td>12.8</td><td>25.6</td></tr>
<tr><td>Tok to Jarvis</td><td>11.7</td><td>23.5</td></tr>
<tr><td>TOTAL</td><td></td><td>76.7</td></tr>
<tr><td rowspan="4">Topology 2 -- 230 kV 795 Single Cond.</td><td>O'Neill to Pump 11</td><td>13.8</td><td>27.6</td></tr>
<tr><td>Gakona to Jarvis</td><td>14.5</td><td>29</td></tr>
<tr><td>Pump 11 to Tok (Radial Line)</td><td>5</td><td>10</td></tr>
<tr><td>TOTAL</td><td></td><td>66.6</td></tr>
</table>

5. The energization cases for the Roadbelt Intertie revealed that approximately -20 MVARs of variable reactor support is needed at Pump 11 and Jarvis in order to match voltage on either side of the open breaker prior to closing. In addition, a significant angle difference across this open breaker (which may prevent a syncho-check relay from allowing a close action) is present if flows from South to North are greater than 50 MW. One solution is to require minimal flows from South to North when closing either the Alaska or Roadbelt Intertie, or to use phase shifting transformers to close the angle difference between Anchorage and Fairbanks prior to energizing one of the interties.

6. The transient stability results indicated that more variable reactive capacity is needed at Pump 11 and Tok for Topology 1, and only at Pump 11 in Topology 2. The recommended SVC ranges accounting for energization and stability following contingencies are highlighted below:

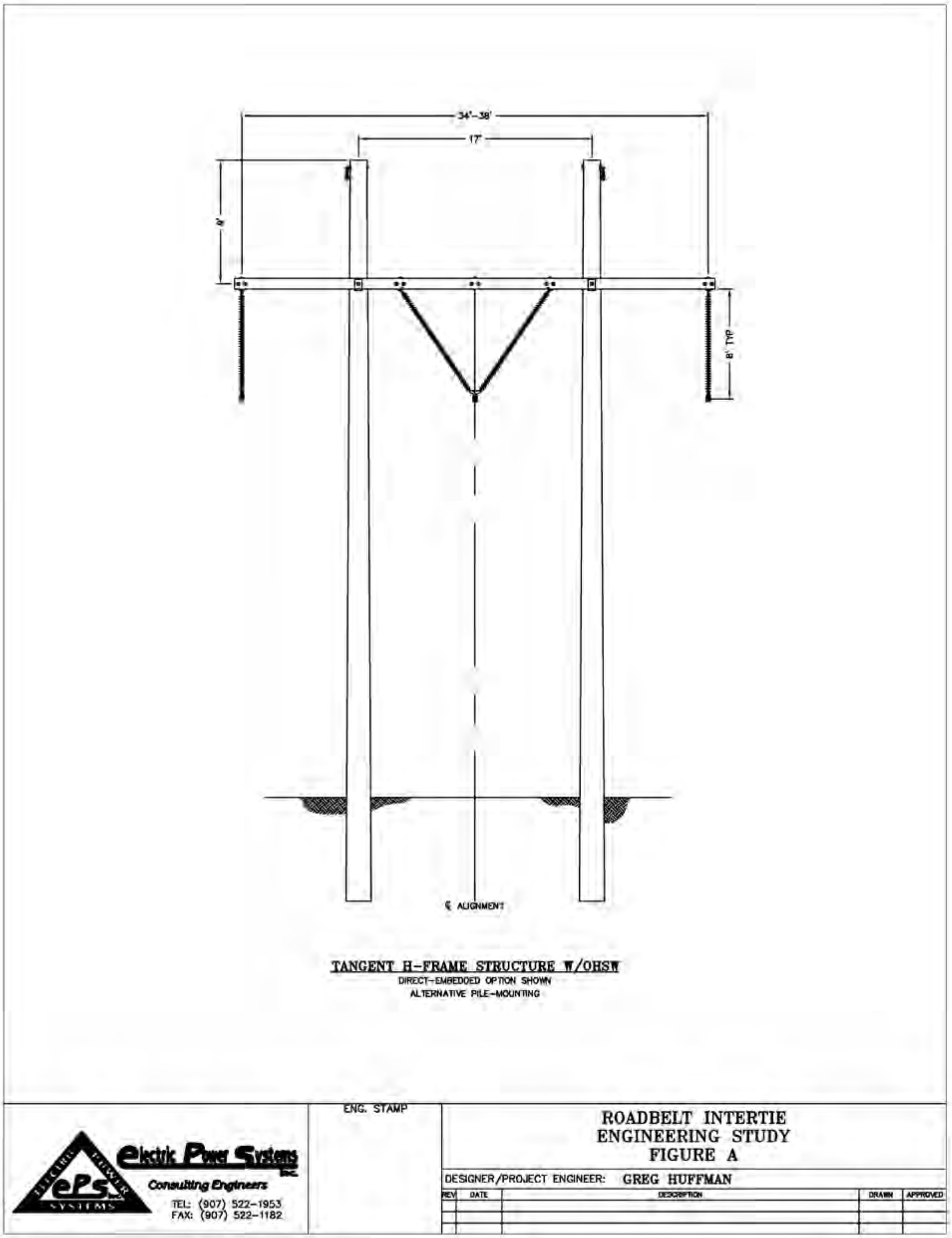
- Topology 1:
  - New Pump 11 SVC: -20 MVAR to +40 MVAR
  - New Tok SVC: -20 MVAR to +30 MVAR

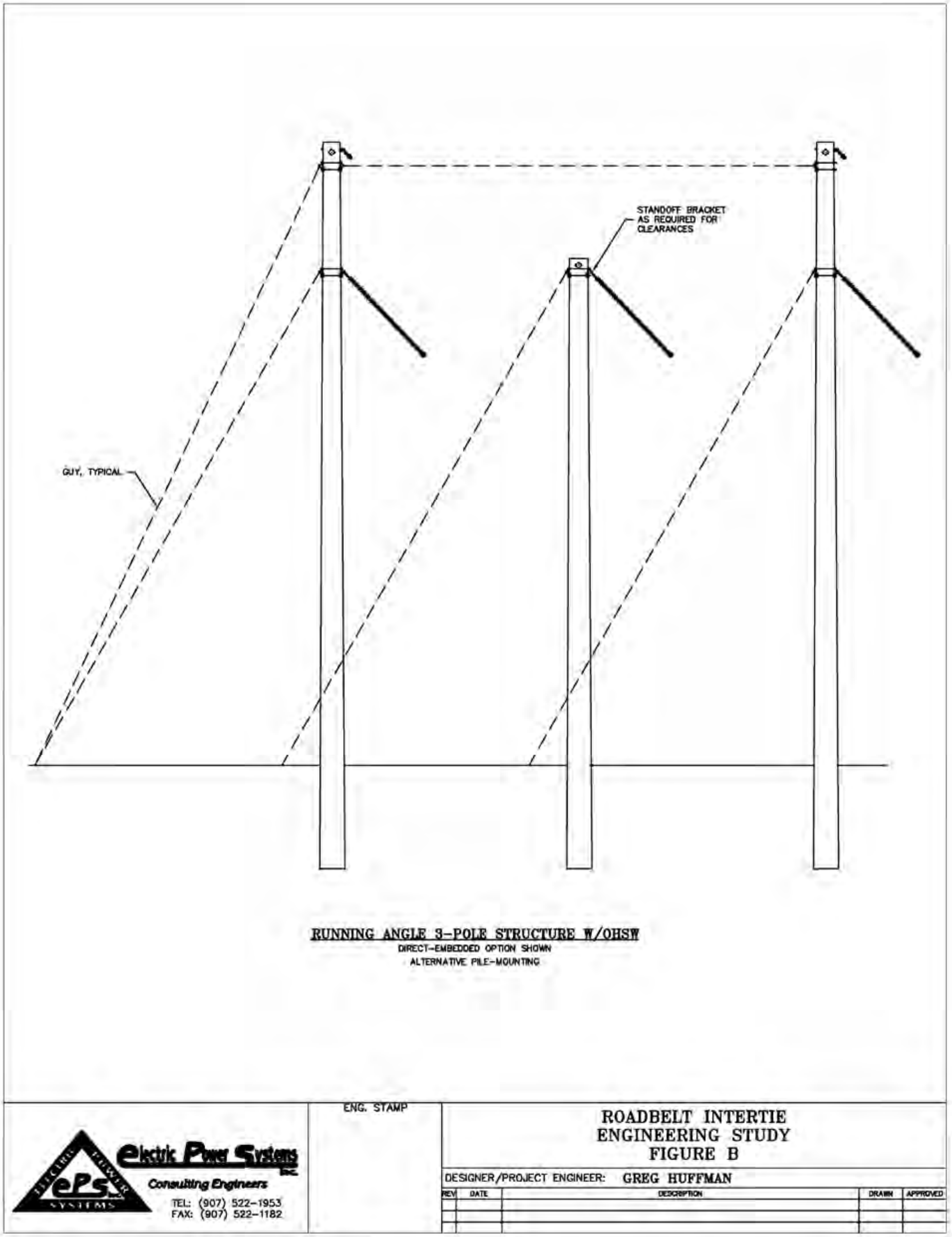
   - Existing Jarvis SVC: -8 MVAR to +45 MVAR
      - With a -18 MVAR Fixed Reactor
- Topology 2:
   - New Pump 11 SVC: -20 MVAR to +30 MVAR
   - Existing Jarvis SVC: -8 MVAR to +45 MVAR
      - With a -18 MVAR Fixed Reactor

7. In addition to dynamically tuned SVCs placed along the Roadbelt Intertie, the GVEA Wilson BESS must be auto-scheduled following any fault that interrupts the high-flow and high-load cases or for a significant loss of generation in the GVEA area. Winter Peak and Summer Peak flows of 125 MW indicated that severe out-of-step trips can occur in both Topology 1 and Topology 2 without additional support via a RAS that auto-schedules the BESS to full output. SVCs alone will not prevent this out-of-step trip from occurring, nor will the BESS RAS alone provide for adequate voltage support. Both solutions are needed. Both Topologies are feasible, however it is apparent that Topology 2 requires less overall reactive support and has less contingencies that require full BESS output to maintain stability.

8. The addition of a new Roadbelt Intertie will also require that the tuning of the Jarvis SVC be revisited. The new intertie significantly changes the electrical characteristics of the system around Jarvis, necessitating a re-tuning of the Jarvis SVC.

Appendix A – Structure Design Figures




STANDOFF BRACKET AS REQUIRED FOR CLEARANCES
GUY, TYPICAL
RUNNING ANGLE 3-POLE STRUCTURE W/OHSW
DIRECT-EMBEDDED OPTION SHOWN
ALTERNATIVE PILE-MOUNTING
Electric Power Systems Inc.
Consulting Engineers
TEL: (907) 522-1953
FAX: (907) 522-1182
ENG. STAMP
ROADBELT INTERTIE
ENGINEERING STUDY
FIGURE B
DESIGNER/PROJECT ENGINEER: GREG HUFFMAN
REV DATE DESCRIPTION DRAWN APPROVED

Appendix B – Cases, Unit Commitment, and Dispatch

Case #	Case 1 & 9	Case 2 & 10	Case 3 & 11	Case 4 & 12	Case 5 & 13	Case 6 & 14	Case 7 & 15	Case 8 & 16
Season	SV	SV	SP	SP	SP	WP	WP	WP
Total Northbound Intertie Flow	20 MW	50 MW	70 MW	75 MW -- Glenallen Intertie Only	125 MW	70 MW	75 MW -- Glenallen Intertie Only	125 MW
WILSON BESS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOLDOTNA 1			25.7	25.7	25.7	28.7	28.7	28.7
BRADLY 1	32.2	32.2	24.3	24.3	22.0	32.4	32.4	32.4
BRADLY 2	18.0	18.0	13.4	13.4	17.0	36.6	36.6	36.6
TESORO 1	1.5	1.5	4.0	4.0	4.0	5.0	5.0	5.0
TESORO 2	1.4	1.4	4.0	4.0	4.0	5.0	5.0	5.0
NIKISKI 1	34.5	34.5	32.2	32.2	32.2	37.6	37.6	37.6
NIKISKI 2	14.4	14.4	20.8	20.8	20.8	15.6	15.6	15.6
PLANT 1 UNIT 3			28.0	28.0	28.0	32.0	32.0	32.0
PLANT 1 UNIT 4			28.0	28.0	28.0			
PLANT 2 UNIT 9	26.5	37.0	44.0	44.0	44.0	49.0	49.0	49.0
PLANT 2 UNIT 10	26.5	37.0	45.0	45.0	45.0	49.0	49.0	49.0
PLANT 2 UNIT 11	10.0	20.0	24.7	24.7	24.7	27.4	27.4	27.4
BELUGA 3					51.5			58.0
BELUGA 5			50.0	50.0	55.0	69.0	69.0	69.0
SPP 11			37.0	37.0	37.0	50.0	50.0	50.0
SPP 12	37.5	37.5	37.0	37.0	37.0	50.0	50.0	50.0
SPP 13	37.6	37.1	37.0	37.0	37.0	50.0	50.0	50.0
SPP 10	19.0	19.0	28.5	28.5	28.5	38.6	38.6	38.6
COOPER 1	10.2	10.2				5.0	5.0	5.0
EKLUTNA HYDRO 1			11.7	12.1	11.6	7.3	12.7	7.3
EKLUTNA HYDRO 2			11.9	11.9	11.9	19.0	19.0	19.0
HCCP#2-G						48.3	48.3	54.0
HLP#1-G	25.2	25.2	25.2	24.5	21.0	20.0	20.0	22.5
EVA WIND	7.9	7.9	6.0	6.0	6.0			
ZENDER 1	8.7							
ZENDER 2	8.7		6.0	5.0				
CHENA 5	23.0	23.0	23.0	23.0	22.4	23.0	23.0	23.0
NORTH POLE CC 3	33.0	23.0	33.0	33.0		48.0	48.0	
NORTH POLE CC 4	7.0	5.1	7.0	7.0		10.6	10.6	
UAF 1	0.5	0.5						
UAF 2	0.5	0.5						
UAF 3	3.0	3.0	7.5	7.5	7.2	6.5	4.0	6.5
FORT WAINWRIGHT 1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
FORT WAINWRIGHT 3			5.0	5.0	5.0	4.0	4.0	4.0
FORT WAINWRIGHT 4			5.0	5.0	5.0	5.0	5.0	5.0
EIELSON 3	5.0	5.0	5.0	5.0	5.0	4.0	4.0	4.0
EIELSON 4			5.0	5.0	5.0	4.0	4.0	4.0
EGS 1	13.7	13.7	14.0	15.0	14.0	14.3	14.3	14.3
EGS 2			14.0	15.0	14.0	14.3	14.3	14.3
EGS 3						14.3	14.3	14.3
EGS 4						14.3	14.3	14.3
EGS 5	13.7	13.7	14.0	15.0	14.0	14.3	14.3	14.3
EGS 6			13.9	14.7	13.9	14.3	14.3	14.3
EGS 7						14.3	14.3	14.3
EGS 9	13.7	13.7	14.0	15.0	14.0	14.3	14.3	14.3
EGS 10			13.9	14.7	13.9	14.3	14.3	14.3
SOLOMON GULCH 1	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
SOLOMON GULCH 2	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
VALDEZ 11	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
VALDEZ 12	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
VALDEZ 4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
VALDEZ 5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
GLENALLEN 6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
GLENALLEN 7	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
ALLISON	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1

SP = Summer Peak, SV = Summer Valley, WP = Winter Peak

(This Page Intentionally Left Blank)