

**HB**

**382**

<TARGET><BILL>HB 382</BILL><SUBJECT>HB  
382</SUBJECT><COMM>HENE30</COMM></TARGET>

# Representative Adam Wool

Alaska State Legislature • District 5 Fairbanks



Chena Ridge • College • University West • Geist • UAF Campus • South Van Horn • Cripple Creek  
Richardson • Parks Highway • Airport • Dale • Lakeview

## Sponsor Statement

### HB 382

**"An Act creating the Railbelt Electrical System Authority;  
and relating to the duties of the Regulatory Commission of Alaska."**

HB 382 calls for the establishment of a Railbelt Electrical System Authority (RESA).

Under HB 382, a Railbelt Electrical System Authority would:

- Manage a unified Railbelt transmission and generation system with the goal of optimizing efficiency;
- Establish nondiscriminatory open access protocols for the transmission system;
- Implement a long-term regional plan for the Railbelt transmission and generation systems.

The Regulatory Commission of Alaska (RCA) will appoint 16 board members to govern the Authority, including three non-voting members. Utility membership on the board will not exceed 5 members for the first 5 years and not exceed 1 member after 10 years. The RCA would have oversight of the RESA. The RESA would function as an independent system operator (ISO), referenced below.

### Background

In a June 30, 2015 letter to the Legislature the RCA noted that "Concerns about the fragmented, balkanized and often contentious Railbelt utilities have been raised numerous times over the past 40 years" and that "Several efforts have been made to reform and reorganize the Railbelt electrical system, but none have succeeded." The letter further states that: "Non-discriminatory access to the grid, open and transparent

system-wide transmission pricing, and economic dispatch of generation by an independent entity are key principles that must guide the transformation of the Railbelt electrical system.”

The RESA would unify the Railbelt utilities and other important stakeholders to oversee region-wide planning for transmission and generation. The RESA would also act like an Independent System Operator (ISO) to perform merit order economic dispatch of the system’s electrical generation assets. Merit order economic dispatch would run only the most efficient electrical generators in the region at any given time, leading to cost savings for electrical consumers and reduced emissions. Open access to the transmission system and a universal transmission tariff would lead to more opportunities for independent power producers to invest in renewable energy projects across the Railbelt.

The Alaska Railbelt Cooperative Transmission & Electric Company (ARCTEC) is a consortium of four of the six Railbelt utilities formed in 2011 with the stated goal to “develop an organization that would adopt and enforce Railbelt reliability standards, conduct Railbelt system planning and ensure open access.” Toward this end, ARCTEC recently hired GDS Associates to facilitate the development of what is being called the Railbelt Reliability Council (RRC), which could someday function like an Independent System Operator. By May 1, 2018, GDS expects to produce a final report and present an MOU containing its recommendations for stakeholders to sign off on before proceeding with the development of a formal RRC business plan.

Formation of a Transmission Company (Transco) has also been proposed by the utilities in association with the American Transmission Company (ATC). To achieve desired results, a Transco should be separate from a RESA/RRC/ISO. If formed, in addition to owning and operating the transmission system, a Transco would execute major maintenance, transmission system upgrades, and new transmission projects necessary for the reliable delivery of electric power consistent with transmission plans developed by a RESA/RRC/ISO.

A draft of GDS’s recommendations was presented to the RCA on March 16<sup>th</sup>. That draft proposed a nine-member governing board for the RRC, with three seats for Railbelt utilities. The GDS draft did not include economic dispatch as a function of the RRC.

# Fiscal Note

State of Alaska  
2018 Legislative Session

Bill Version: HB 382  
Fiscal Note Number: \_\_\_\_\_  
( ) Publish Date: \_\_\_\_\_

Identifier: HB382-DCCED-RCA-03-23-18  
Title: RAILBELT ELEC. TRANSMISSION AUTHORITY  
Sponsor: WOOL  
Requester: (H) Energy

Department: Department of Commerce, Community and  
Economic Development  
Appropriation: Regulatory Commission of Alaska  
Allocation: Regulatory Commission of Alaska  
OMB Component Number: 2417

## Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2019 Appropriation Requested	Included in Governor's FY2019 Request	Out-Year Cost Estimates				
			FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
<b>OPERATING EXPENDITURES</b>	<b>FY 2019</b>	<b>FY 2019</b>	<b>FY 2020</b>	<b>FY 2021</b>	<b>FY 2022</b>	<b>FY 2023</b>	<b>FY 2024</b>
Personal Services	188.7		188.7	188.7	188.7	188.7	188.7
Travel							
Services	30.0		30.0	30.0	30.0	30.0	30.0
Commodities	20.0						
Capital Outlay							
Grants & Benefits							
Miscellaneous							
<b>Total Operating</b>	<b>238.7</b>	<b>0.0</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>

## Fund Source (Operating Only)

1141 RCA Rcpts (DGF)	238.7		218.7	218.7	218.7	218.7	218.7
<b>Total</b>	<b>238.7</b>	<b>0.0</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>

## Positions

Full-time	2.0		2.0	2.0	2.0	2.0	2.0
Part-time							
Temporary							

## Change in Revenues

1141 RCA Rcpts (DGF)	238.7		218.7	218.7	218.7	218.7	218.7
<b>Total</b>	<b>238.7</b>	<b>0.0</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>	<b>218.7</b>

**Estimated SUPPLEMENTAL (FY2018) cost:** 0.0 *(separate supplemental appropriation required)*  
*(discuss reasons and fund source(s) in analysis section)*

**Estimated CAPITAL (FY2019) cost:** 0.0 *(separate capital appropriation required)*  
*(discuss reasons and fund source(s) in analysis section)*

## ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? Yes  
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/23

## Why this fiscal note differs from previous version/comments:

Not applicable, initial version.

Prepared By: Stephen McAlpine, Chairman Phone: (907)276-6222  
Division: Regulatory Commission of Alaska Date: 03/23/2018  
Approved By: Catherine Reardon, Director Date: 03/23/2018  
Agency: Division of Administrative Services, DCCED

FISCAL NOTE ANALYSIS

STATE OF ALASKA  
2018 LEGISLATIVE SESSION

BILL NO. HB 382

Analysis

House Bill 382 requires the Regulatory Commission of Alaska (RCA) to establish by January 1, 2019, a Railbelt Electric System Authority (RESA) that would manage the electric generation and transmission system for the Railbelt area, determining the optimal electric generation output to meet system load at lowest cost and consolidating operations and tariffs for the Railbelt area. The RESA entity would be a division of the RCA and would be charged with preparing and submitting a transmission tariff for the Railbelt region, establishing and enforcing interconnection and reliability standards, and performing regional transmission and generation planning.

House Bill 382 requires the RCA to provide staffing for RESA. Initial RCA work efforts would include establishing codes of conduct and operational protocols for the entity. The RCA may opt to pursue these operational guidelines through a rulemaking proceeding in order to enshrine codes of conduct and operational protocols in regulation.

Subsequent RCA efforts would include coordinating the preparation and submission of a single transmission tariff for the Railbelt; reviewing and approving the tariff; preparing, submitting, and approving revisions to the transmission tariff; assisting in the establishment of interconnection and reliability standards for the Railbelt; and assisting in the periodic preparation and submission of a regional transmission and generation plan. The RCA may also be called upon to hold hearings intended to mandate compliance with interconnection and reliability standards.

Two additional full-time positions and associated support costs would be required to manage the additional workload associated with this legislation.

- Personal Services: \$188.7 (two full-time permanent positions: Utility Engineering Analyst III, range 22; and Law Office Assistant I, range 11)
- Services: \$30.0 (annual statewide core services reimbursable services agreements for human resources, financial support, mail, software licenses, and department support costs)
- Commodities: \$20.0 in the first year (computers, furniture, and other one-time needs)

The RCA is funded by the Regulatory Cost Charge, which is set to approximately equal the budgets of the RCA and the Department of Law's public advocacy function per AS 42.05.254 and AS 42.06.286.

Chairman Adam Wool  
House Special Committee on Energy  
State Capitol, Room 412  
Juneau, Alaska 998011-1182

March 28, 2018

Dear Chairman Wool and Members of the Committee:

Renewable Energy Alaska Project is statewide, non-profit coalition of over 80 dues-paying diverse energy stakeholder organizations. We have been working to promote renewable energy, energy efficiency and energy literacy across Alaska since 2004. I am writing this letter to respectfully encourage the Committee to pass HB 382. There are several important issues that relate to the Railbelt's future contained in the bill:

### **Reliability Standards**

One important issue for the Railbelt is the creation and enforcement of electric reliability standards across the entire region. These standards are essential to ensure that the transmission system, and the "dispatch" (use of) the region's electrical generators is as efficient and safe as possible, including threats against cyber security. In the Regulatory Commission of Alaska's June 30, 2015 letter to the Legislature, the Commission made several findings and recommendations regarding the Railbelt. One of those findings was that region-wide reliability standards were both necessary *and lacking* in the Railbelt. In its letter, the Commission gave the utilities time to voluntarily come up with uniform regional reliability standards.

It is now nearly three years later and reliability standards have still not been agreed to by the utilities. Four of the six Railbelt utilities that have formed an organization called the "Alaska Railbelt Transmission and Electric Company" (ARCTEC) recently hired an outside technical advisor from Georgia called GDS Associates to look at reliability and other Railbelt issues, and make recommendations as to the form and function of a new organization that ARCTEC is proposing to call the Railbelt Reliability Council, or RRC. Note the word "reliability" in the title of the RRC. GDS is over halfway through a process of talking to stakeholders and making its recommendations and is scheduled to wrap up its process near the beginning of May. GDS is hoping to get agreement from a range of stakeholders on a Memorandum of Understanding that would be the beginning of the formation of the so-called RRC.

While REAP appreciates the effort that ARCTEC (as well as non-ARTEC utilities Homer Electric Association and Anchorage Municipal Light and Power) are making through the GDS process, unfortunately REAP *does not believe* that the voluntary process that the RCA has requested the utilities to engage in will ultimately be successful. There is simply too disagreement amongst the utilities. As mentioned, two of the six utilities are not aligned enough with the others to even belong to ARCTEC, and the utilities repeatedly fail to speak with one voice. More importantly, each of the six utilities has a fiduciary responsibility *to its respective members*, and *not to the region*. Since none of the utilities has an explicit responsibility to the region, it is REAP's belief that the legislature must declare that reliability and other standards be established through the proposed Railbelt Electrical System Authority, or RESA, contained in HB 382. There is no disagreement that the region needs reliability standards – the real question is how we are ever going to get there from here. The RESA would ensure that standards are set, and then enforced by the RCA.

## Economic Dispatch

For at least the last four years, the driving force behind the formation of a new entity in the Railbelt has been *saving consumers money* by ensuring that the most efficient generators in the region are being run in a logical order, from the most efficient generator first, to the second most efficient second, the third most efficient third, and so on, as the electrical demand *in the region* goes up and down. This is known as “merit order economic dispatch.” At present, merit order economic dispatch is not being done in the Railbelt region. Instead, each respective utility is balancing supply and demand of electricity in their own respective service areas. Since today the utilities are connected by transmission lines, as opposed to when they were first established over 70 years ago, economic dispatch in the entire region is technically feasible. However, despite some bilateral contracts and the sharing of state-owned resources like the Bradley Lake hydro facility, the six Railbelt utilities are *not* dispatching their respective generation assets *on a regional basis*. This is inherently inefficient. It means that less efficient generators are being run in the region when they could remain idle, allowing the sale of more economic energy to flow from the most efficient generators. This inefficiency unnecessarily consumes more fuel. Burning more fuel in inefficient generators costs Railbelt consumers money.

The need for merit order dispatch was recognized and called out by the RCA in its 2015 letter to the legislature. In that letter, the Commission set the utilities on a course to voluntarily come up with a model for merit order economic dispatch of the *region’s* generation assets, instead of the utilities continuing to balance supply and demand in their respective, smaller and suboptimal, service areas.

Almost three years after the Commission’s letter to the legislature, there is still no economic dispatch in the Railbelt. Over a year ago, Chugach Electric Association, Anchorage Municipal Light and Power and Matanuska Electric Association announced to the Commission that those three utilities that serve parts of Anchorage were going to form what they called a “tight power pool” as a precursor to region wide economic dispatch. They told the Commission they would need an additional year to sort out how they would settle the sharing of their generation assets. That additional year has now come and gone and there is still no tight power pool in the Anchorage area. Furthermore, there is little consistency and transparency about how those negotiations are going. Instead, the public hears one story from one utility about how the pool is progressing, and another story from another utility. The “pool” has no designated spokesperson.

While there may be some disagreement about how much merit order dispatch can be done in the entire region that stretches from Homer to Fairbanks without transmission upgrades to the north and south from Anchorage, the RCA and the public were told that the tight power pool would be possible, and indeed operating, by a few months ago.

What should be very disturbing to Railbelt electric consumers is that fact that ARCTEC’s consultant GDS is no longer recommending that the so-called Railbelt Reliability Council that it is formulating for the utilities *even include* the function of economic dispatch. The reason that GDS gave to the Commission at a RCA public workshop held March 16, 2018 is that there is fundamental disagreement among the parties about the basis for economic dispatch. This is still another example of how conflict among the six utilities hurts the region as a whole. REAP believes that merit order dispatch of the region’s generating assets *must* be a function of any new entity that is established for the Railbelt.

## Non-Discriminatory Open Access to Transmission

There are at least two problems with the way new entities or projects can currently try to access the Railbelt transmission system.

First, today each single utility handles interconnection within their respective service area. There are six utility transmission owners in the Railbelt, along with the Alaska Energy Authority. This means the

process that an independent power producer must go through to send power into the grid from a project varies from utility to utility. There is no region-wide, consistent and transparent set of rules for accessing the transmission system, a system that has been constructed entirely from public money of one sort or the other (federal, state, municipal or cooperative). This lack of predictability chills investment from the private sector that Alaska sorely needs.

Second, there is not one single tariff, or charge, to move electrons across the Railbelt. In fact, in some cases there are what is referred to as “pancaking” transmission tariffs. This is a situation where the movement of electrons from A to B incurs multiple tariffs from different transmission owners that are stacked (or pancaked) on top of each other. Such redundant costs to transmit electricity have serious economic consequences for consumers.

### **Region-Wide Planning**

REAP believes that region-wide planning for the Railbelt is one of the most important functions that a new Railbelt Electrical System Authority could handle. The Railbelt has never been planned as one region. One recent result of this lack of planning has been the overbuilding of generation assets in the Railbelt. In its 2015 letter to the legislature, the RCA noted that the Railbelt utilities have collectively built \$1.5 billion dollars of new generation projects in the last several years. With the exception of the Southcentral Power Plant that Chugach and ML&P built together, none of those new generation assets were built with a regional approach in mind. This lack of regional planning also extended to how new generation assets are impacting the existing transmission system. It is also worth noting that in comparison to the \$1.5 billion the utilities spent on new generation, those same utilities spent next to nothing on transmission system upgrades.

Now that the lack of regional planning has resulted in more new electric generation in the Railbelt than what was necessary for the region as a collective whole, Railbelt consumers are on the hook to pay for those capital expenditures. Each of the respective utilities that built power plants committed their members to pay back those expenditures for the next 25-30 years. Incredibly, this was done without either MEA or HEA having any long-term contracts for natural gas, and both Chugach and ML&P likely to run out of the gas reserves they now own long before the new generation assets are paid for. You might ask why the RCA did not prevent the utilities from building unnecessary generation, or generation that is vulnerable to fuel price volatility? The answer is that the RCA does not have what is known as “siting authority” over each respective utility’s decision to build new generation. If the Commission had siting authority, it could pre-approve new generation projects *before* power plants were built. Instead, without siting authority, the RCA’s hands are tied until *after* a utility has already made its decision to plan, finance and construct a new power plant. Only after the power plant is built and the utility and its consumers are committed to paying for it does the RCA have a role. That role is to hear the utility’s request to charge a tariff to its customers to pay the investment back. This lack of siting authority by the Commission has forced it to allow those tariff requests in case after case because to deny the tariff would cause financial havoc for a utility that has already built a power plant.

Regional planning would take into account what new generation assets the *entire region* needs, and therefore avoid a repeat in the future of the overbuilding that has recently happened in the Railbelt. Regional planning would also take into account where potential renewable energy assets could be located, both relative to the resource’s proximity to the need for power, and its proximity to transmission. Giving a new Railbelt Electrical System Authority the ability to plan for both new generation and transmission assets allows generation and transmission asset decisions to be made in the context of each other, and on a regional basis. This is far more effective than making generation decisions for each Railbelt utility service district in isolation of what the neighboring utility has decided to do, or not do. It is also more efficient to plan for the regional electrical system as just that, *a system* that includes generation assets *and* the transmission assets necessary to move the electrons efficiently to market. Having the Railbelt Electrical

System Authority objectively decide which transmission projects are a priority for the region also protects consumers from the impacts from a future, for-profit transmission utility building transmission that does not have positive long-term benefits relative to its cost. Regional planning means that the best possible decisions get made for the entire Railbelt, saving consumers money. However, region-wide planning must include stakeholders besides the six Railbelt utilities.

### **Diverse Governance Structure**

The governance structure of the proposed Railbelt Electrical System Authority is perhaps the most important part of HB 382. Without the proper balance of independence and stakeholder input from other sectors of Alaskan society besides the six Railbelt electric utilities, Alaskans will see no real change in the way business is done in the Railbelt.

Seventy-seven years ago, when my local electric utility in the Matanuska Valley was formed, I think the concept of a local cooperative meant something very different to the citizens of Palmer than it does today. Though Matanuska Electric Association is still a cooperative, most of its members do not participate in its governance. In fact, in the Railbelt it is pretty typical for utility board elections to draw less than 20% of a cooperative's eligible voters. Ask the average electric consumer today what kind of legal structure their electric utility is and they are likely to say they don't know. In contrast, when MEA was formed in 1941, there wasn't any electricity in Palmer. People were joining together to provide it, with an assumption and social compact that they would remain accountable to each other.

Since the six Railbelt utilities were formed decades ago, road systems, electric transmission lines, and telephone and internet service have all come to the region. The RCA itself has stated that if we were start over today, we would certainly have just one utility in the Railbelt. For context, the *combined average electric load of all six Railbelt utilities is just over 600 MW*. In contrast, a typical *power plant* (not utility) in the Lower 48 is around 1,000 MW. While REAP is not advocating for all six utilities to be made into one, what the Railbelt Electrical System Authority would do is make sure that all six utilities take full advantage of the fact that today they are connected. The region's future prosperity depends on it.

Besides the transmission, road and communication infrastructure that has been built over the last decades, there are other changes and trends that the current system of six independently operated utilities cannot effectively address. For example, over the decades there has been an increase in the number of commercial and industrial electrical consumers in the region. Those consumers are a stakeholder group that should have input into planning the region's electrical system. Another change has been the meteoric drop in the cost of renewable electricity from wind and solar, even as the efficiency of those technologies continues to increase. For example, in 1990, the average price of wind power in the United States was 65 cents/kWh. Today, the average *unsubsidized* price for wind in the Lower 48 has dropped to under 5 cents/kWh, making it competitive with natural gas and coal. Likewise, the price of utility-scale solar has dropped precipitously in the last 10 years, with the average *unsubsidized* price now also down to around 5 cents/kWh. In 2017, nearly half of all new generating capacity additions in the United States were wind or solar. In the rest of the world, most of those wind and solar installations are being developed by independent power producers, companies that specialize in those technologies and are therefore most often in the best position to build projects as efficiently as possible. Independent power producers are another constituency that must be at the table when plans are made for our electric future.

There are other trends that are not being effectively addressed or represented in the current system of six utilities that make decisions independent of each other. One is the increasing use of "distributed" power. This refers to both an accelerating number of people in the Railbelt who are putting cheap solar panels on their homes, and businesses who are finding it more economical to generate their own power *on-site*, often coupled with energy storage. Those businesses and consumers need a seat at the table.

Another major trend is energy efficiency. As more consumers have been made aware of how energy efficient lighting and appliances can save them money, the demand for electricity in the Railbelt has actually been *decreasing*, even as the region as whole has overbuilt generation. Fortuitously, another trend that can counter that decrease in demand is electric vehicles, or EVs. EVs, and the lithium ion batteries that run them, are coming down in price so fast that many experts, investors, nations and car companies are betting on them to completely change the way we transport ourselves. The cost of operating a Chevy Bolt or Tesla Model 3 with a range of over 200 miles that one can purchase *today* for about \$35,000 (*before* a federal tax credit of up to \$7,500) is half of what it costs to operate a standard car with an internal combustion engine. Even with the Railbelt's relatively expensive 20 cent/kWh power, a Chevy Bolt can go 200 miles on \$12 worth of electricity. In contrast, a person with a car that gets 25 mpg and uses \$3/gallon gasoline would spend \$24 to go the same 200 miles. EVs also have only about 20 moving parts, as opposed to roughly 2,000 moving parts in the internal combustion engines of today, making EVs cheaper to maintain and likely to last much longer. As the price of EVs continues to drop every year, a transportation revolution is brewing. It is imperative that the governance structure of a new Railbelt Electrical System Authority also have people and entities on the governing board who understand how the trends of energy efficiency and electric transportation fit together so they can help the Railbelt prepare for its future.

Besides different types of electric consumers, independent power producers, and renewable, efficiency and electric vehicle stakeholders, other entities that should be represented on the governance structure of the Railbelt Electric System Authority include the Alaska Energy Authority (AEA), the RCA itself and a representative of any new transmission utility that might be formed in the future.

Just two weeks ago, ARCTEC's consultant, GDS Associates, made a preliminary recommendation in front of the RCA that the governing board of ARCTEC's proposed Railbelt Reliability Council be made up of nine members, with just three seats held by Railbelt utilities. This preliminary recommendation is further evidence that a diverse group stakeholders, not just the same six utility players, must guide the Railbelt's future. It is also consistent with the language in HB 382, which states that no more than 40% of the governing board of the Railbelt Electrical System Authority come from the six existing Railbelt utilities.

If the governance structure of the Railbelt System Authority did not include the wide array of Alaskans that have a stake in how the region plans for and then produces and transmits electricity, Alaskans will see more of the same conflict among the utilities who are now running the show, and Alaska will continue to lag behind other states and nations that have embraced regional electric systems and renewable energy. A wide variety of non-utility stakeholders are part of the governance in those so-called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in other jurisdictions.

The Railbelt needs a vision of our future that is based on objective reality, not six often competing versions of it. Indeed, it is utility disagreement over what the region needs that GDS pointed to when it told the RCA on March 16<sup>th</sup> that it was not including the function of economic dispatch in ARCTEC's proposed Railbelt Reliability Council. Instead, GDS is currently proposing that the RRC be stood up first, and then a wide group of stakeholders could design still another study to determine whether it makes sense to have only the most efficient generators operating in the Railbelt at any one moment in time.

By not including economic dispatch in the RRC's functions, GDS is essentially saying that Alaskans need to spend more time and more money on more studies to determine what common sense tells us is true: that consumers will save money if natural gas is not burned inefficiently. This conclusion by GDS underscores why we need a Railbelt Electrical System Authority now, and why the utilities cannot control it. If Alaska is going to do what other jurisdictions have now done for decades and make the planning and operations of our electrical system more efficient on a regional basis, we cannot afford to continue to wait for the utilities to address these issues voluntarily.

## Conclusion

Today we are at an important crossroads for the Railbelt, and for the state. If Alaska is going to diversify its economy, the Railbelt will have a major role to play. Energy efficiency, electric vehicles, renewable energy and distributed energy are all making what was for many decades a relatively static electric industry one of the most dynamic and fast changing industries on the planet. The Railbelt Electrical System Authority is necessary for the Railbelt's six independent utilities to come together to meet today's trends and challenges. Today, the six Railbelt utilities still do not speak with one voice, in large part because their respective fiduciary duties are to their own members, and not to the region. While efforts to pool generation resources around Anchorage, and to look at new models like an RRC are commendable, consumers cannot wait any longer for the utilities to voluntarily put something together with the requisite functions and governance structure. Consumers are already on the hook for more generation capacity than the region as a whole needed, and the resulting higher electricity prices in the Railbelt will impact consumers all over the state as the target electricity price for the Power Cost Equalization program rises higher and higher.

Alaska can also no longer afford to operate with a balkanized Railbelt electricity system. We need regional planning, economic dispatch and reliability standards to protect consumers and transparent and consistent interconnection standards to attract investment. Most importantly, we need a governance structure for the Railbelt Electrical System Authority that does not rely on utilities alone to plan the region's future. Consumers and investors have waited long enough for voluntarily action. The utilities' RRC model will not get us to where the region must go. Instead, REAP respectfully suggests that you, the elected representatives of the state's consumers, take the required action to establish the Railbelt Electrical System Authority. Thank you very much for your consideration of this critical issue. I am always available to answer any questions that you may have, or to provide background materials.

Sincerely,

A handwritten signature in black ink, appearing to read "Chris Rose".

Chris Rose  
Executive Director

## HB 382 Support Letter

**From:** SlatonBarker, Tony [mailto:slatonbarker@coffman.com]

**Sent:** Friday, March 23, 2018 8:46 AM

**To:** Sen. Mia Costello <Sen.Mia.Costello@akleg.gov>; Sen. Cathy Giessel <Sen.Cathy.Giessel@akleg.gov>; Sen. Kevin Meyer <Sen.Kevin.Meyer@akleg.gov>; Sen. Gary Stevens <Sen.Gary.Stevens@akleg.gov>; Sen. Shelley Hughes <sen.shelley.hughes@akleg.gov>; representative.kurt.olson@akleg.gov; Rep. Gabrielle LeDoux <Rep.Gabrielle.LeDoux@akleg.gov>; Rep. Cathy Tilton <Rep.Cathy.Tilton@akleg.gov>; Rep. Andy Josephson <Rep.Andy.Josephson@akleg.gov>; Rep. Sam Kito <Rep.Sam.Kito@akleg.gov>; Rep. Mike Chenault <Rep.Mike.Chenault@akleg.gov>

**Subject:** HB 382 support creating Rail Belt Electrical System Authority

Dear Legislators,

I would like to voice my high level of support for HB 382. Alaska is far behind the times in regards to grid management and efficient power system management. We need a single system operator to provide for the most cost effective power production, transmission and reliability standards. The lower 48 has developed this system and it is providing for effective and cheaper power production across the grid. It is very inefficient to have 6 different entities managing power production, generation and transmission across the railbelt.

Without a single rail belt operator, each individual utility will do what is most efficient for their members in the short term, even if it is more costly overall to rail belt consumers overall.

Please support the creation of this Railbelt Electrical System Authority.

Thank you for your time and service.

Regards,

**Tony SlatonBarker, P.E., S.E., LEED AP**

Vice President

Principal, Energy and Sustainability

**Coffman Engineers, Inc.**

800 F Street | Anchorage, AK 99501

p 907.276.6664 | f 907.276.5042 | c 907.257.9229 [www.coffman.com](http://www.coffman.com)

March 28, 2018

Dear Members of the Energy Committee,

I would like to voice my support for HB 382 regarding the creation of a Railbelt Electrical System Authority. Based on my understanding of the railbelt electrical system, gained primarily from my participation in the Member Advisory Committee at Golden Valley Electrical Association, I believe this bill will help lower energy costs within the rail belt and allow for increasing use of cost effective and clean renewable energy resources.

At present, the Railbelt transmission and generation system is too disjointed and could be optimized with a system of merit order economic dispatch, better planning and coordination, all of which would be provided by the bill.

Thank you,  
Andrew McDonnell  
2595 Allen Adale Rd.  
Fairbanks, AK 99709

Representative Adam Wool  
Alaska State Legislature  
Juneau, AK

*Dear Representative Wool and Energy Committee members,*

*We are writing on behalf the Alaska Climate Action Network (AK CAN!), a statewide coalition of community-based groups, individuals, climate scientists, Indigenous leaders and renewable energy experts and advocates across Alaska.*

*We request that HB 382 be amended to include management of integrated grid-scale energy storage systems with the Railbelt energy generation and transmission facilities already included.*

*We define "grid scale energy storage" as "an energy storage facility capable of acting as a whole grid peaker and load balancing plant, with sufficient energy storage to power the entire grid for eight or more hours a day." These energy storage facilities would replace the utilities' very expensive load balancing and spinning reserve peakers and allow the integration of unlimited variable renewable energy generation, including wind, solar, tidal, wave, and micro-hydro, among others.*

*It appears that the 2009 REGA study suggested the original model for this bill, and Anchorage area utilities more recent uncoordinated build-out provided the impetus. In 2009, grid scale energy storage for Alaska was not yet on anyone's radar. When HB 382 was originally crafted as HB 172, grid scale energy storage was still not widely foreseen as a possible option for Alaska. Quite recently that has changed. Two technologies, one new and one older technology we're repackaging for Alaska are emerging.*

*New battery technologies are currently driving rapid penetration of electric transport and industrial trucks and equipment. Everyone probably remembers that Moore's Law predicted that transistor density would double every two years. That law held for 50 years. Fewer are familiar with Swanson's Law, which observes that solar installation doubles every two years, and prices drop by 20% with every doubling. That rule has held for thirty years and has only recently changed. That change is that the doubling rate has increased from two years to a year and a half.*

*In 2009 during the REGA study, there were no mass produced Plug-in Electric Vehicles (PEVs). PEV sales currently comprise 2% of global sales, and those sales are doubling every year and a half, same as solar. At that rate, within ten years all new vehicles sold will be PEVs. Also less acknowledged but no less real, all types of transportation will likely be converting at the same rate. Battery manufacturing seems able to keep up, and very few bottlenecks appear likely.*

*That penetration is increasing the likelihood of massive grid demand overloads when whole fleets of electric cars and trucks are plugged in each evening to recharge, if not well managed. On the other hand, if well managed at grid scale, vehicle-to-grid (V2G) battery management could altogether eliminate the need for spinning reserves and also allow nearly cost-free integration of low cost variable renewable energy sources. That in turn would encourage the rapid expansion of independent power providers, eliminating the need for the utilities to add more gas-fired generation units, and reducing the consumption of natural gas.*

*The older technology is Pumped Hydro Energy Storage. The specific site being looked at now and a basic specs are described in two articles that can be found at:*

*<http://www.alaskansknowclimatechange.com/100--renewable-alaska.html> and <https://craigmedred.news/2018/03/09/the-eklutna-battery/>*

*Pumped hydro would be suitable for seasonal storage, able to load balance Alaska's extreme seasonality. That's a function no other technology can yet accomplish, and the combination of pumped hydro and wind or solar could provide very cheap and clean energy, and enough of it to attract very large users, such as the giant server farms and industrial customers that Iceland runs their economy on.*

*We support HB 382 whether or not our requested amendments are included and ask that it be expedited and not held in committee any further.*

*Alaska has the most diverse world-class renewable energy resources in the Nation. We strongly believe that an aggressive and immediate transition to a renewable energy-based economy is vital to the state's economic recovery and future.*

*Thank you,*

*Kerry Williams & Ceal Smith*

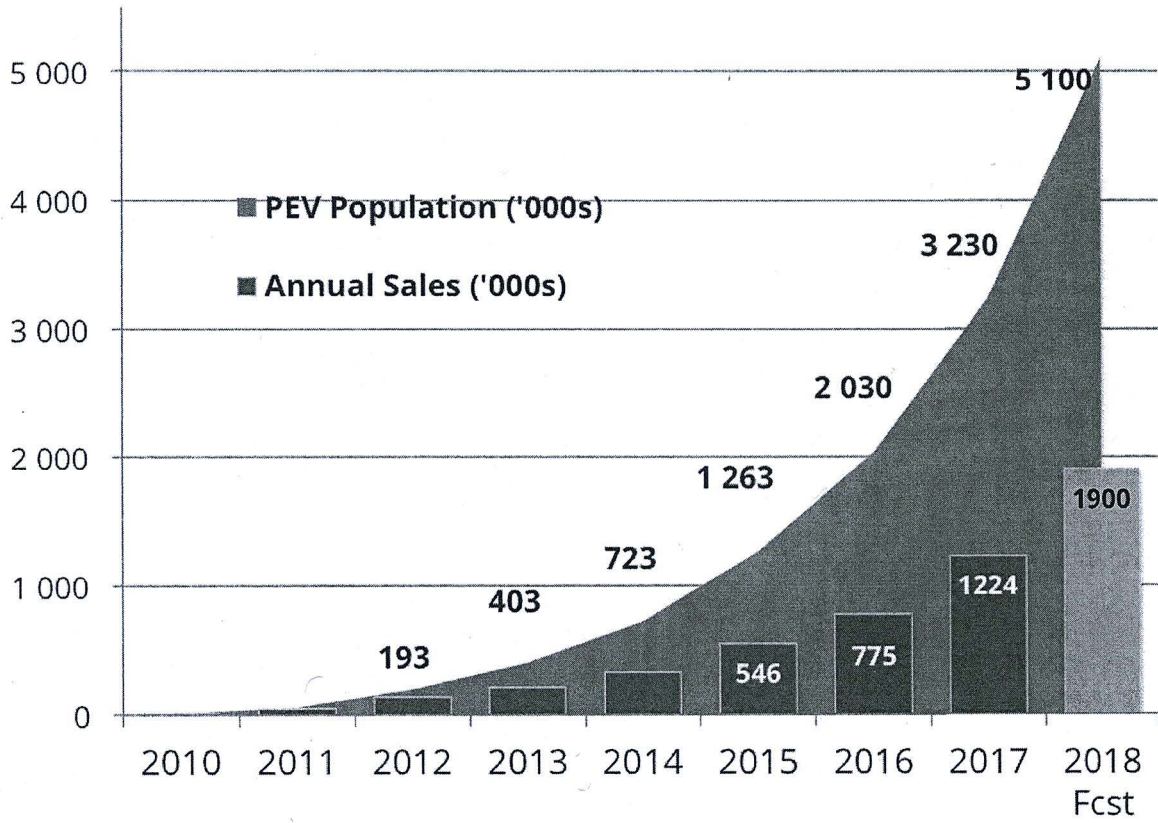
*Alaska Climate Action Network (AK CLEAN!)*

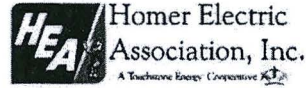
*Eagle River, AK*

*(907) 248-4224/952-7472*

# Global Plug-in Vehicle Population

EV VOLUMES.COM





March 27, 2018

Dear Chair Wool and House Special Committee on Energy Members:

We appreciate the opportunity to discuss the progress of Railbelt collaboration during the discussion of House Bill 382. In the two and one-half years since the Regulatory Commission of Alaska (RCA) issued its letter to the legislature directing voluntary efforts by the Railbelt utilities, we have made significant progress not previously seen and significantly faster than similar efforts in the Lower 48.

Most recently, utilities commissioned a facilitated, consensus-driven process to develop a Railbelt operational framework. This system-wide effort is being led by GDS Inc., an objective, third-party expert and is inclusive of a broad range of stakeholders including Renewable Energy Alaska Project (REAP), the Alaska Energy Authority (AEA), CIRI, American Transmission Company (ATC), the Alaska Independent Power Producers Association (AIPPA), and others, including a self-nomination process. This effort has been under careful scrutiny of the RCA that has conducted two public workshops and directed several informational filings on the matter.

This effort has established common ground on items like governance, scope and the function of such an operational model. With their expertise in independent system operators and regional transmission organizations across the Lower 48, GDS is bringing proven solutions, ground-truthing our ideas and acknowledging the obvious biases of each of the stakeholders. Their solution is one where none of the parties get exactly what they want, but each has a path forward they can live with. We believe it represents a solution that is best for all Alaskans living in the Railbelt region, not just special interests.

This sort of voluntary collaboration between the utilities has proven effective in recent history. Numerous voluntary efforts by the Railbelt utilities are presently working in an effective manner and include:

- Chugach, MEA and ML&P have entered into an MOU to move forward with contractual economic dispatch and are in the testing phase with plans to file with the RCA later this year.
- After a considerable modeling effort involving unprecedented information sharing, we now have a model detailing the value of economic dispatch that all Railbelt utilities agree on.
- We have all signed an MOU with ATC to continue discussions around a potential Transco organization to manage the transmission system and are working through the details of cost-sharing and governance.
- We have hired GDS to recommend an organizational model for reliability standards, open access and regional planning that will be complete and presented to the RCA in the next 2 months, inclusive of all relevant stakeholder voices. In addition, the recommended organization will be able to further efforts to study the costs and benefits of single system economic dispatch.
- We have been operating a voluntary power market called a 'loose power pool' that has saved the utilities' ratepayers millions of dollars annually in recent years. This expands the use of shared generation, building on what the original three generating utilities have done since the construction of the Alaska Intertie.

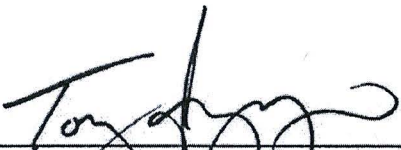
As public power cooperatives and municipal utilities, our decisions are firmly grounded in the impact to our ratepayers. We are concerned with other models and solutions driven by interested parties that do not have fiduciary responsibilities to our ratepayers. For this reason, we oppose House Bill 382 because we believe it is important to let the current collaborative process reach its conclusion and allow the RCA to ultimately decide what, if any, statutory changes are required.

The Railbelt utilities understand the value of working together towards solutions. We continue to make progress towards cooperation and move into a future of collaboration that brings value to the entire region. We invite others to do the same.

This bill represents one small stakeholder group legislating the outcome of a mediated, facilitated independent process. We urge you to allow the considerable progress that has been made through voluntary efforts and independent expertise to continue.

Sincerely,

  
\_\_\_\_\_  
Lee Thibert, Chief Executive Officer  
Chugach Electric Association, Inc.

  
\_\_\_\_\_  
Anthony M. Izzo, CEO General Manager  
Matanuska Electric Association, Inc.

  
\_\_\_\_\_  
Brad Janorschke, General Manager  
Homer Electric Association, Inc.

\_\_\_\_\_  
Cory Borgeson, Chief Executive Officer  
Golden Valley Electric Association, Inc.

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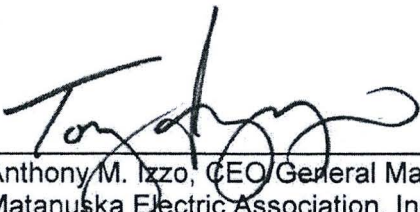
Sincerely,

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Lee Thibert, Chief Executive Officer  
Chugach Electric Association, Inc.


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Brad Janorschke, General Manager  
Homer Electric Association, Inc.



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Anthony M. Izzo, CEO/General Manager  
Matanuska Electric Association, Inc.



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Cory Borgeson, Chief Executive Officer  
Golden Valley Electric Association, Inc.



STATE OF ALASKA  
DEPARTMENT OF  
**COMMERCE**  
COMMUNITY AND  
ECONOMIC DEVELOPMENT

*Bill Walker, Governor  
Chris Hladick, Commissioner  
Robert M. Pickett, Chairman*

---

Regulatory Commission of Alaska

June 30, 2015

The Honorable Kevin Meyer  
President of the Senate  
Alaska State Senate  
716 W. Fourth Avenue, Suite 500  
Anchorage, Alaska 99501

The Honorable Mike Chenault  
Speaker of the House of Representatives  
Alaska House of Representatives  
145 Main Street, Loop, Suite 223  
Kenai, Alaska 99611

Dear Senator Meyer and Mr. Chenault:

Subject: Regulatory Commission of Alaska Recommendation to Legislature

The 2014 Alaska Legislature directed the Regulatory Commission of Alaska (RCA or Commission) to provide a recommendation on “whether creating an independent system operator or similar structure in the Railbelt area is the best option for effective and efficient electrical transmission.” Concerns about the fragmented, balkanized and often contentious Railbelt utilities have been raised numerous times over the past 40 years. Several efforts have been made to reform and reorganize the Railbelt electrical system, but none have succeeded.

Significant investment totaling approximately \$1.5 billion has been made in new Railbelt electrical generation over the past five years. This level of capital expenditures by the four cooperative electric utilities, one municipally owned electric utility and one independent power producer is unprecedented. To realize the maximum benefit from this investment, the Railbelt electrical transmission system and generation must be operated in the most effective and efficient manner possible. The key question is does the current institutional structure allow the maximum benefits to be realized? Is there evidence to believe the current system is not optimal? If the electrical system in the Railbelt has opportunity for improvement, what are the options and how do we best get there?

A limited \$250,000 capital appropriation was made available to the RCA for this project in the FY 2015 Capital Budget. In July 2014 the RCA initiated an agreement with the Alaska Center for Energy and Power (ACEP) to secure the advisory services of Dr. Antony Scott and access to economic and power system modeling services. The RCA in its scope of work with ACEP considered the efficient transmission of electrical energy to include both the short-term operation of existing assets (including generation assets), and the efficient planning and construction of new-build assets. One broad task area included modeling that identifies potential consequences of reforming Railbelt grid institutions, identifying the benefits available from more efficient operation of the system as it exists today. Assessing the degree to which new transmission assets

701 W. 8th Avenue, Suite 300, Anchorage, Alaska 99501-3469  
Telephone: (907) 276-6222 Fax: (907) 276-0160 TTY: (907) 276-4533  
Website: <http://rca.alaska.gov>

may unlock new efficiencies and value was also included in this first task. The second broad task area analyzed the policy options for Railbelt reform, with a critical assessment of a range of potential mechanisms that might be pursued, including costs and feasibility, in the Railbelt context.

If the Railbelt electrical system were a blank slate today and the current institutional facts on the ground didn't exist, a single utility owning and operating all of the generation, transmission, and distribution assets would probably be the most efficient and effective system. That is not the situation we have today. It is not realistic to believe some form of a public power entity will be created with public dollars to purchase the Railbelt electric utilities' assets. Purchase of all the Railbelt electric utilities' assets by an investor-owned utility is also unlikely given the various governing structures and debt encumbrances. The State of Alaska's serious financial constraints make significant State contributions to the Railbelt's unfolding electric transmission needs a highly improbable scenario. Our recommendation to the Legislature has been shaped by a clear view of our current reality and by a desire to identify a path forward that is actually attainable and that benefits ratepayers in the Railbelt.

A key weakness in the current Railbelt electrical system is the lack of an institutional structure to finance significant transmission assets crossing the service areas of several utilities. In 2014 the Alaska Energy Authority released the Alaska Railbelt Transmission Plan, prepared by Electric Power Systems (EPS) Consulting Engineers. This report included the findings of the Pre-Watana and Post-Watana studies completed to determine the future needs of the Railbelt transmission system. The prioritization of the pre-Watana projects was also included. Priority transmission system projects totaling an estimated \$900 million were identified. Annual projected savings from these projects was estimated to be between \$146 and \$241 million. Funding and financing mechanisms for these transmission priorities were not addressed in the EPS report.

The RCA and ACEP reviewed the modeling and assumptions underlying the EPS report. After critically assessing the EPS modeling work, new model runs were developed to address several key questions:

1. What are the key factors that drive the benefits of economic dispatch?
2. What are the benefits of economic dispatch, as separate from the benefits of relieving transmission constraints in the Railbelt?
3. Who would win and who might stand to lose under a system of economic dispatch?

In contrast to the EPS modeling, the new modeling done for the RCA legislative report developed and incorporated reasonable, indicative postage-stamp rates for transmission (for both the existing system and the new-build transmission). The annual reports of the Railbelt electric utilities were analyzed to determine a reasonable approximation of net book value, operating expenditures (OpEx), and expected remaining life of current transmission assets. A standard rate base rate of return model then incorporated these inputs.

The RCA legislative report needed to answer several key questions:

1. What does an economically efficient electrical system look like?
2. Is there reason to believe that the Railbelt is not a fully efficient system?
3. What can we learn from the previous efforts at reform?
4. What are the ranges of generic policy instruments to move towards greater efficiency in the Railbelt?
5. What are specific examples of Independent System Operator (ISO)/Transco models, and how applicable are they to the Railbelt situation?

A critical component of developing the RCA's recommendation to the Alaska Legislature is the public process used, with input from a wide range of interested parties. A robust record was established, with numerous opportunities provided for presentations, suggestions and criticisms. A preliminary PDF version of the record is attached to the electronic version of this letter. The complete hard copy of the record will be provided upon completion of its preparation.

**At a Special Public Meeting on Monday, June 29, 2015, the Commission made the following findings and recommendations.**

**Finding No. 1:** The present Railbelt electrical transmission system requires institutional reform. The balkanized ownership of transmission assets and the system's evolution under legacy power purchase agreements constrain and limit the effective and efficient operation of the Railbelt grid. The Commission believes that no significant state funding will be available for Railbelt transmission replacement and upgrades. No institutional structure currently exists that is capable of providing significant capital for transmission projects that cross the service territories of several Railbelt utilities.

**Recommendation No. 1:** An independent transmission company should be created to operate the transmission system reliably and transparently and to plan and execute major maintenance, transmission system upgrades, and new transmission projects necessary for the reliable delivery of electric power to Railbelt customers. This independent transmission company should be certificated and regulated as a public utility under AS 42.05. The RCA should be granted siting authority for new generation and transmission, and granted explicit authority to regulate integrated resource planning in the Railbelt electrical system. A mandatory report on the status of the current efforts to develop an independent Railbelt electric transmission company shall be filed with the Commission no later than September 30, 2015. A second report on transmission restructuring shall be filed with the Commission no later than December 31, 2015. Failure to file these reports will be construed as a failure of the current voluntary efforts to develop an independent Railbelt electric transmission company. If voluntary efforts fail, the Commission will work with the Legislature and the Administration to develop and implement specific legislation and to prioritize actions necessary to create an independent Railbelt electric transmission company.

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**Finding No. 2:** Although short-term bilateral economy energy transactions occur in the Railbelt electric market, true economic dispatch of generation units on a system-wide basis does not occur. The Railbelt electric system does not deliver the maximum benefit possible to ratepayers, who will be paying for approximately \$1.5 billion for new generation. The various ISOs existing in the lower 48 are appropriate in very large, fully restructured, unbundled markets. This ISO model in the Railbelt electrical system is an overly complex institution for a limited number of generation units and relatively small loads. Other models may be more appropriate for the Railbelt grid. Non-discriminatory access to the grid, open and transparent system-wide transmission pricing, and economic dispatch of generation by an independent entity are key principles that must guide the transformation of the Railbelt electrical system.

**Recommendation No. 2:** System-wide merit order economic dispatch of the Railbelt's electrical generation units will bring the maximum benefit to ratepayers. The Commission should use all the regulatory and statutory authority it currently has to strongly promote economic dispatch, and seek new statutory authority as needed to promote this goal. Voluntary efforts by the utilities to utilize loose power pools should be encouraged as an interim step towards a tighter power pooling system. As actual data is generated concerning costs, benefits and other outcomes of voluntary power pooling strategies, quarterly reports shall be filed with the Commission. These reports will be analyzed and reviewed to assess the organizational and governance structure needed for an independent consolidated system operator. The first report shall be for the fourth quarter of 2015 (October 1, 2015 through December 31, 2015) and shall be filed no later than January 30, 2016. Quarterly reports shall be filed with the Commission throughout 2016, due no later than 30 days after the end of the applicable reporting quarter. Failure to file these quarterly reports will be construed as a failure of voluntary efforts to move towards system-wide merit order economic dispatch. If voluntary efforts fail, the Commission will work with the Legislature and the Administration to develop and implement specific action steps to institutionalize system-wide merit order dispatch.

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**Finding No. 3:** Many past efforts to reform and rationalize the Railbelt electrical system have failed. Substantial time and money has been expended on consulting reports, endless meetings, legislative hearings, and many frustrating hours in the RCA's East Hearing Room. A great deal of skepticism exists about the ability of the electric utilities to voluntarily reform and restructure the Railbelt grid and move towards true merit order economic dispatch. Non-utility independent power producers and larger institutional customers have complained about the current structure, and insist that a level playing field is needed. A lack of trust and continued reliance upon state legislative appropriations for transmission has contributed to this dysfunctional history.

**Recommendation No. 3:** Though history strongly indicates that the current voluntary transmission restructuring and economic dispatch efforts by the utilities may fail, the Commission believes the utilities must be given the opportunity to succeed. The timelines

outlined in Recommendations 1 and 2 allow for this potential success. Failure of the voluntary efforts and initiatives will trigger the compulsory steps identified in Recommendations 1 and 2.

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**Finding No. 4:** Reliability standards for the Railbelt electrical grid are voluntary and not all electric utilities have adopted the same standards. The Intertie Management Committee (IMC) formally adopted the Railbelt Operating and Reliability Standards at its meeting on November 1, 2013. The IMC includes the Alaska Energy Authority and the Participating Utilities (Chugach Electric Association, Inc.; Golden Valley Electric Association, Inc.; Matanuska Electric Association, Inc.; and the Municipality of Anchorage dba Municipal Light and Power). The IMC voluntarily filed its Reliability standards with the Regulatory Commission of Alaska on January 27, 2014. On December 9, 2014, Homer Electric Association for itself and on behalf of Alaska Electric and Energy Cooperative voluntarily filed with the RCA the Reliability Standards of the Railbelt Reliability Committee as Modified and Adopted by Homer Electric Association.

**Recommendation No. 4:** Enforceable and consistent Railbelt operating and reliability standards are necessary for consistent, safe, reliable, and efficient operation of the Railbelt electric system. The RCA strongly encourages the IMC and Homer Electric to resolve their differences and develop a common Railbelt operating and reliability standard. In January 2016 the RCA will initiate a process to determine if it should adopt regulations concerning Railbelt operating and reliability standards.

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**Finding No. 5:** The first four RCA recommendations above will be challenging and time consuming. Full implementation of the proposed Railbelt electrical system structural changes will likely take five to ten years. Many obstacles remain to be overcome. The time critical recommendations identified above are a start, but many additional, concrete building blocks must be identified in the months ahead. Many different parties must cooperate or this effort will fail. The Legislature, the Administration, Railbelt utilities, independent power producers, the RCA, Department of Law, Regulatory Affairs & Public Advocacy, and most of all the ratepayers have much at stake. RCA resources will be stretched and stressed as the structural reform of the Railbelt electrical system progresses.

**Recommendation No. 5:** The RCA will be hugely impacted by these proposed Railbelt electric system changes. The initial action steps will need to be implemented within existing RCA resources. The Commission is self-supporting through regulatory cost charges (RCCs), and does not rely upon state undesignated general funds. If the RCA receives the necessary Administration and Legislative support, the FY 2017 RCA budget will require the necessary RCC funded resources to implement these proposed recommendations.

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The Honorable Kevin Meyer and The Honorable Mike Chenault  
Page 6 of 6  
June 30, 2015

Each of the findings and recommendations were voted upon individually at the June 29, 2015, RCA Special Public Meeting and all were passed unanimously. These recommendations are respectfully submitted to the Legislature for its review and consideration. Upon request, the Regulatory Commission of Alaska will assist the Legislature in developing solutions addressing these critical issues. Thank you for the opportunity to provide this information to you.

Respectfully,

A handwritten signature in black ink that reads "Robert M. Pickett". The signature is written in a cursive style with a large, prominent "R" and "P".

Robert M. Pickett  
Chairman

cc: The Honorable Bill Walker, Governor  
Commissioner Chris Hladick, DCCED

By e-mail with preliminary PDF version of the record

# FACILITATION OF THE RAILBELT RELIABILITY COUNCIL (RRC)

2<sup>ND</sup> TECHNICAL CONFERENCE – REGULATORY COMMISSION OF ALASKA  
MARCH 16, 2018



*This information is for discussion purposes only. It is provided for the sole purpose of facilitating discussion for developing alternatives for consideration by ARCTEC's Board, Participants, and Interested Parties. Until formally approved by ARCTEC's Board, this material or any discussions surrounding it have not been endorsed or approved by ARCTEC or its Members.*

# DISCUSSION OUTLINE

- Update on the Process
- Stakeholder Outreach
- RCA Jurisdiction
- Reliability Standards
- RRC Scope
- RRC Governance Structure



## UPDATE ON THE PROCESS

- Presented at the January 26, 2018 RCA Technical Conference
- Response to Order No. 3, Docket 1-16-002
  - Filed update on the facilitation process (3/7/18)
  - Conducted a technical conference involving all interested parties (3/13/18)
  - Summary of comments received from Stakeholders and Interested Parties to be filed (3/20/18)



## STAKEHOLDER AND INTERESTED PARTY OUTREACH

- Alaska Energy Authority
- Alaska Independent Power Producer Association
- American Transmission Company
- Anchorage Municipal Power & Light
- ARCTEC Board
- ARES EIF
- Chugach Electric Association
- CIRI
- Doyon Utilities
- Golden Valley Electric Association
- Homer Electric Association
- Matanuska Electric Association
- RAPA
- REAP
- Seward Electric Association



## RCA JURISDICTION

- ✓ RCA approves the establishment of reliability, security, and other operating standards
- ✓ RCA retains authority to review and approve investments and administrative costs of the RRC
- ✓ RCA is the ultimate arbiter of reliability and network access disputes

***-- These acknowledgments will be part of the MOU  
and subsequent RCA documents --***



## RELIABILITY STANDARDS

- The six utilities are developing consensus reliability standards to govern Railbelt grid operations
- As agreed to in their MOU of October 11, 2017 they will file a report on these standards on April 1<sup>st</sup> 2018
- These standards, for informational purposes, will be filed as expeditiously as practical
- It is anticipated that these standards will serve as “Version 1.0” reliability standards for adoption, administration, monitoring, and enforcement



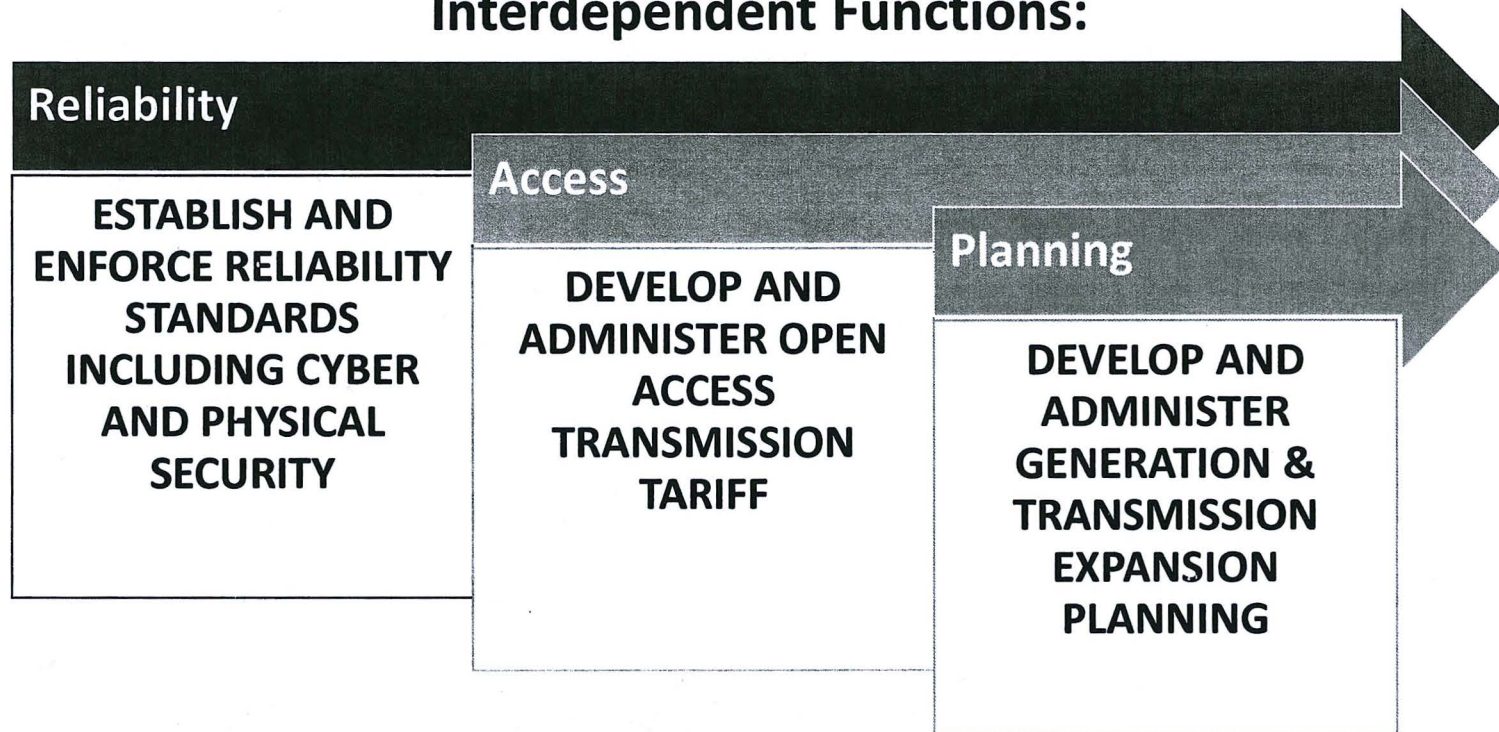
# RELIABILITY STANDARDS

- Railbelt Managers have created the Railbelt Cybersecurity Working Group
- This group is developing a scope of work and budget, including consulting support, to enable the collaborative establishment of a single set of enforceable cybersecurity standards
- The Railbelt Cybersecurity Working Group will be incorporated into the RRC when established



# RRC SCOPE AND FUNCTIONS

## Interdependent Functions:



# RRC SCOPE AND FUNCTIONS

## Key Takeaways:

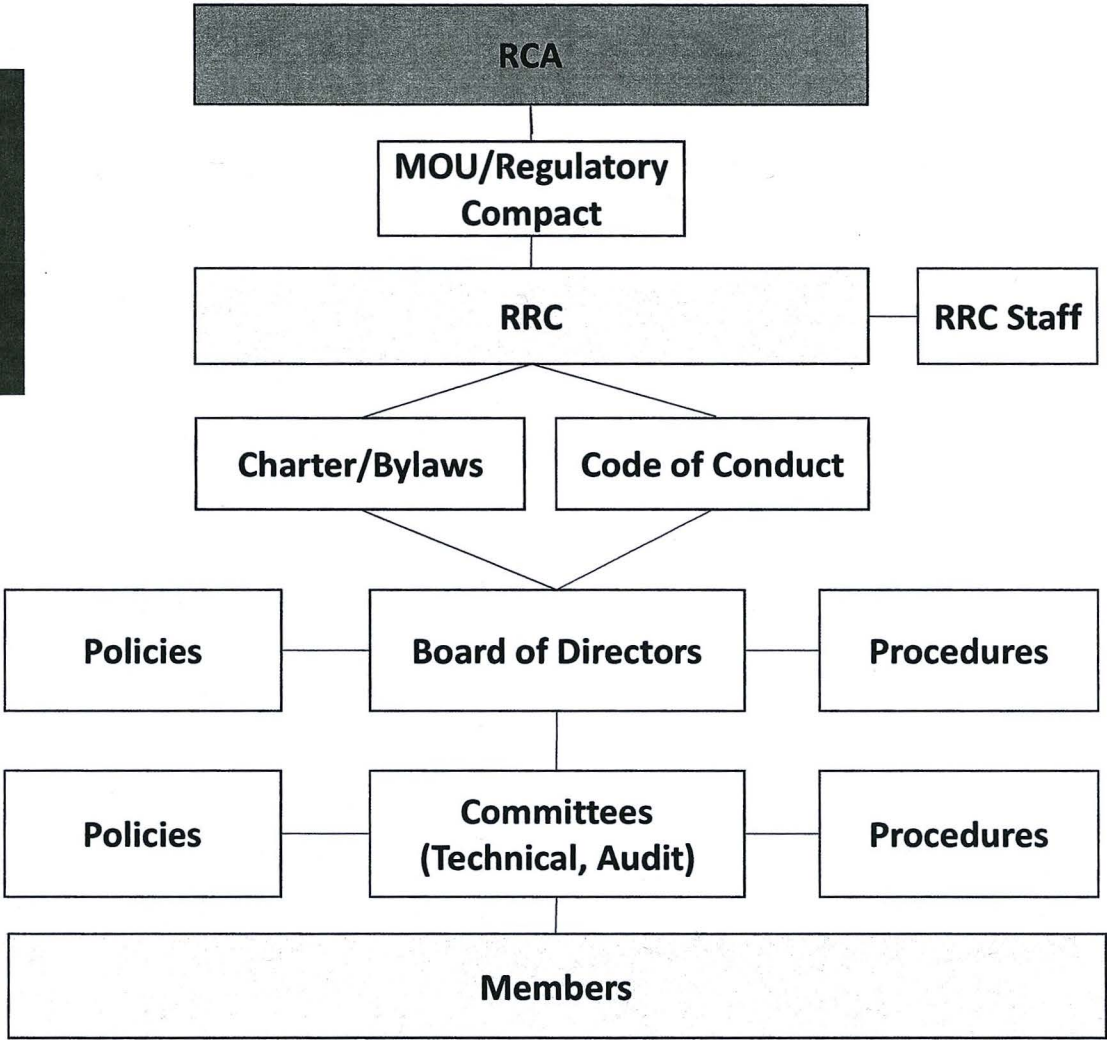
- Protocols, planning, and informational postings will provide transparency to Stakeholders
- RRC Scope and Functions as shown can work in concert with a Transco
- Economic dispatch monitoring and evaluation of potential costs and savings will provide needed information to Stakeholders



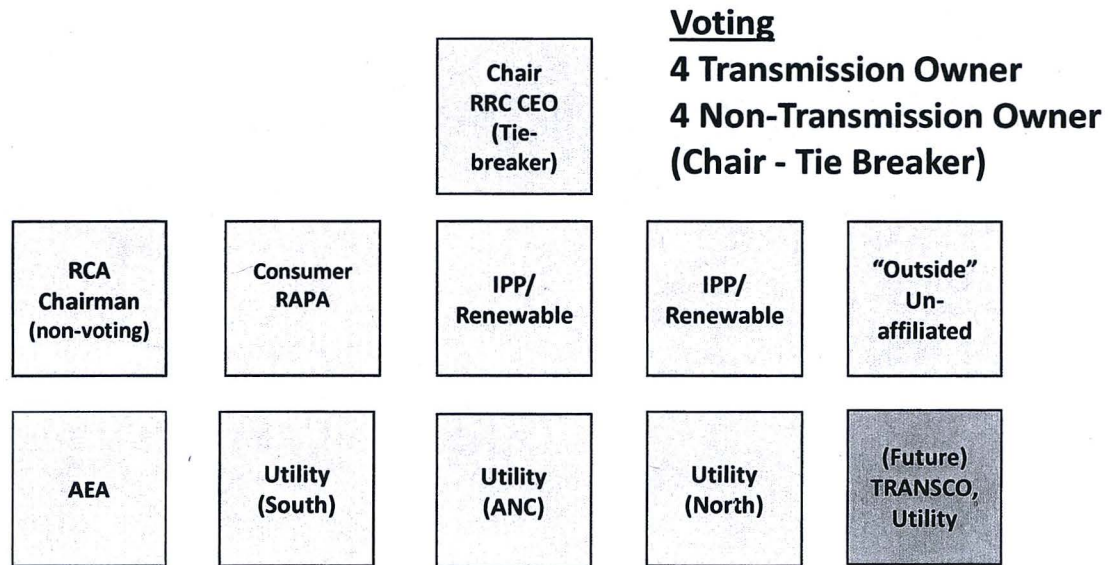
# RRC GOVERNANCE STRUCTURE

*RCA will have  
full jurisdiction  
over the RRC*

*RRC will be  
Stakeholder  
Driven*



# RRC BOARD OF DIRECTORS RECOMMENDATION



**Notes:**

- All terms are 3 years unless indicated otherwise.
- Must meet qualifications. Outside director – academia, retired utility exec, etc.
- Board expands for addition of new Transmission Owners (TRANSCO, Utility, etc.)

# RRC MOU/REGULATORY COMPACT

## *Key Process Deliverable ---> Recommended MOU*

### What will it do?

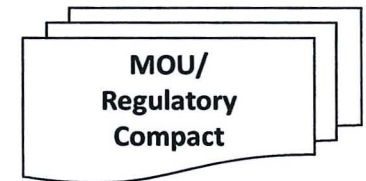
- Document consensus on an RRC
- Recognize the RCA retains full authority over the RRC

### What will it contain?

- Outline the RRC's Structure and Scope
- Commitment to develop a formal RRC Business Plan

### Who will be party to it?

- All Utility Participants to be signatory
- To be acknowledged by the RCA & Interested Parties



**MOU**  
**(Memorandum of Understanding is a Written Document)**

# RRC FACILITATION PROCESS - SUMMARY NEXT STEPS

- Continue collaboration with Stakeholders
- Follow-up meetings as necessary
- Develop Final Report and recommended MOU



# RRC FACILITATION COMMUNICATIONS

**Please continue to send comments and questions to:**

[AlaskaRailbeltUtilities@gdsassociates.com](mailto:AlaskaRailbeltUtilities@gdsassociates.com)

Seth Brown (O) 770-799-2456

Paul Wielgus (O) 770-799-2461



# RRC FACILITATION PROCESS

*Thanks for your time and attention  
and your continued input and support going forward!*



# Railbelt Energy System: USO/ISO/RRC Discussion for the House Energy Committee

Janet Reiser  
Executive Director

Kirk Warren  
Railbelt Energy Projects Director

March 29, 2018



ALASKA ENERGY AUTHORITY

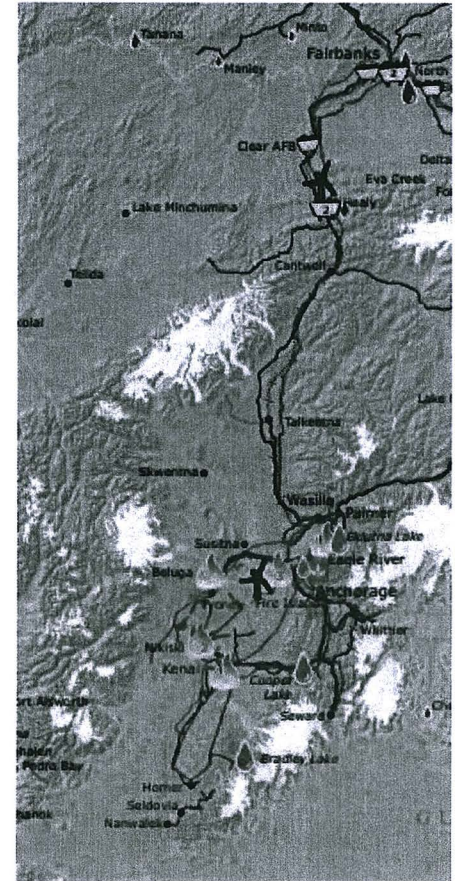


**SAFE,  
RELIABLE, &  
AFFORDABLE  
ENERGY  
SOLUTIONS**

REDUCING THE COST OF ENERGY IN ALASKA

# Railbelt electricity reform

1. Background: what's the issue and how was it created?
2. What is needed to improve efficiency within the Railbelt system?
3. What has already been done to that end?
4. What needs remain?
5. How can this need be met?
6. What is AEA offering as assistance?



# 1. Background: what's the issue and how was it created?

- Siloed electrification of Southcentral AK created inefficiencies.

**1940's** MEA, Eklutna Lake

**1950's** CEA Ship Creek, Cooper Lake

**1960's** CEA Beluga, GVEA Healy Coal

**1970's** Demand growth; transmission focus

**1980's** Hydro years; APA/AEA formed  
Railbelt Energy Fund ('86)



# 1. Background: what's the issue and how was it created?

- Siloed electrification of Southcentral AK created inefficiencies.
  - Lack of centralized planning
  - Inherent conflict of fiduciary responsibilities
  - Interconnected system operation is not optimized
  - No accountability for reconciled reliability standards
  - Pancaked tariffs are a disincentive to IPPs



# 1. Background: what's the issue and how was it created?

- Siloed electrification of Southcentral AK created inefficiencies.
- Three previous attempts to restructure in order to capture cost savings through administrative efficiencies were not successful.

**1986** When Railbelt Energy Fund was established

**1998** Joint Committee on electric utility restructuring established

**2003** Alaska Energy Policy Task Force



# 1. Background: what's the issue and how was it created?

- Siloed electrification of Southcentral AK created inefficiencies.
- Three previous attempts to restructure in order to capture cost savings through administrative efficiencies were not successful.
- The current (4th) attempt to restructure has been in the works for a decade.

**2008** Railbelt Electrical Grid Authority (REGA)

**2010** Greater Railbelt Energy & Transmission Company (GRETC)

**2011** Railbelt Integrated Resource Plan (RIRP) Completed

**2014** AEA Published Draft Transmission Plan

**2017** AEA Published Final Transmission Plan



## 2. What is needed to improve efficiency within the Railbelt system?

- The Railbelt System requires institutional reform
- Economic Dispatch by an independent entity is a key principle which must guide this reform.
- That the utilities be given time to undertake these efforts voluntarily.
- That the utilities Reconcile disparate reliability Standards.



### 3. What has already been done to that end?

- The Railbelt System requires institutional reform
- Economic Dispatch by an independent entity is a key principle which must guide this reform.
- That the utilities be given time to undertake these efforts voluntarily.
- That the utilities reconcile disparate reliability Standards.
  - Working toward tight pool
  - Reliability standards reconciled
  - ARCTEC hired GDS to facilitate stakeholder engagement



## 4. What needs remain?

- Consistent, transparent process for managing Railbelt power now and into the future for the greatest region-wide public benefit
  - Realize maximum potential savings
  - Ensure a regional perspective is taken
  - Inclusivity is critical – utilities as well as other stakeholders



## 4. What needs remain?

- Consistent, transparent process for managing Railbelt power now and into the future for the greatest region-wide public benefit
- The body overseeing that process must have accountability to the public through an audit function of that central authority
  - The public has a right to know what's going on



## 5. How can this need be met?

### **Establish a USO with the following guiding principles:**

- Sector Representation with no majority control by any one sector
- Transparent/Public decision making processes
- Responsibilities must include
  - Economic Dispatch
  - Establish/Enforce Reliability Standards
  - Develop and Administer Open Access Transmission Tariff
  - System Wide Planning



## 5. How can this need be met?

<b>Function</b>	<b>HB 382</b>	<b>GDS</b>	<b>AEA</b>
Economic Dispatch as core function	X		X
Sets Railbelt-wide Reliability Standards	X	X	X
Regional planning authority	X	X	X
Sets open access interconnection standards	X	X	X
<b>Form</b>			
New private entity		X	
New state entity, subdivision of RCA	X		
New entity (TBD), admin housed at AEA			X
Paid for by ratepayers	X	X	X
<b>Governance</b>			
Utilities have minority Board membership	X	X	X
16 member board - Includes stakeholders and independents	X		
10 member board - Includes stakeholders and Independents		X	X
Mandatory Utility Membership	X	?	X
Under RCA jurisdiction	?	X	X



## 6. What is AEA offering as assistance?

### 1. Facilitation, coordination, and leadership in forming a Railbelt Unified System Operator

The scope of the USO should include:

- Reliability standards
- Regional planning (i.e. Railbelt system)
- Economic dispatch
- Interconnection standards



## 6. What is AEA offering as assistance?

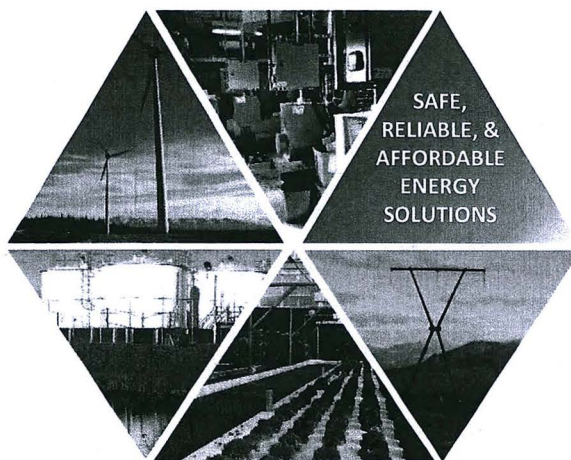
1. Facilitation, coordination, and leadership in forming a Railbelt Unified System Operator
2. Housing the USO at AEA, and performing all back-office functions
  - Operational/administrative efficiencies
  - Coordinated, objective reporting to legislature
  - Connected to strategic resource planning within the region
  - Expected to be utility funded (similar to IMC/BPMC) through efficiency savings



# What is AEA ***NOT*** proposing?

1. We are not proposing to do this by ourselves or be the enforcer
2. We are not proposing a specific structure; that needs to be worked out with stakeholders and make sense to ratepayers
3. We are not proposing to exclude the utilities or other stakeholder groups
4. We are not proposing to make the rules





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**Alaska Energy Authority  
Railbelt Transmission Plan  
Project #15-0481**

**March 6, 2017**

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## 1 Introduction

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This report includes the findings of the transmission system analysis and economic studies completed to determine the future composition of the Railbelt transmission system.

Since the last draft report was issued in March 2014, new reliability and operating standards have been adopted by the Railbelt utilities, and new generation plants for all utilities have been commissioned. Additionally, the Railbelt utilities have spent considerable effort reviewing and updating the economic models used to simulate the Railbelt's cost of power production. As a result of the new standards, new power plants, and the utilities' work on the economic model; the transmission studies have been updated to reflect 2016 conditions, and the economic studies have been updated to use the latest economic models available from the utilities. Since the economic studies do not include the total economic evaluation of the projects, but only evaluate possible fuel savings, they are presented as a separate report, apart from the technical system studies.

The purpose of this plan is to outline a transmission system and improvement projects necessary to meet the requirements of the Railbelt Transmission System Planning Standard, AKTPL-001-4. Per the standard, once a proposed project is identified, each project must undergo a process that includes economic and reliability evaluations to justify its construction. This plan outlines the transmission system improvements required to meet the standard, but does not attempt to complete each projects' analysis required in the standard to determine if and when it should be constructed.

The transmission system improvements needed to support the Watana project, or any other major generation project not currently under construction or completed are not included in the report.

## 2 Executive Summary

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Electric Power Systems (EPS) has completed an analysis to determine the future transmission system in the Railbelt. The need for the transmission plan was driven by the changes in the Railbelt generation and transmission system since the completion of the 2010 Regional Integrated Resource Plan (RIRP) administered by the Alaska Energy Authority (AEA).

The recommended transmission system improves reliability and has the potential to mitigate future cost increases to Railbelt ratepayers and allow significant energy transfers between different areas of the Railbelt system. Constraints for the use of Bradley Lake hydroelectric project energy are removed and the coordination of hydro and thermal generation resources throughout the Railbelt can be optimized. While the proposed reliability improvements are far from what would be required for a transmission system in the Lower 48, they do significantly improve the reliability and economics of the Railbelt and allow the utilities to pursue additional load and resource pooling options not possible with the existing transmission system. The proposed improvements allow increased use of variable renewable generation, such as wind and photovoltaic (PV) in the Railbelt system, which is currently near its limit of renewable resource penetration.

Most transmission improvements are typically justified by the cost of unserved energy, or the value of system reliability, and are rarely justified purely on hard economic benefits. However, there is currently no uniform estimate of unserved energy throughout the Railbelt, nor are there adequate records or criteria to allow it to be equitably evaluated. Typically, in the Lower 48, the types of reliability improvements included within this plan are required as part of the power

systems' mandate to meet NERC's and/or the transmission areas' reliability criteria. Projects are not evaluated solely in terms of the pure economic benefit of the project for fuel savings or reduced losses. For this reason, the economic evaluation of these projects is not included in this portion of the study. The economic model developed for the production cost simulations has been made available to the utilities, along with the results of the analysis in a separate document for the utilities to complete the evaluation in accordance with AKTPL-001-4.

This report is not a mandate to construct these projects, but rather should be considered the first step in the transmission planning process outlined in the recently completed transmission planning standard, specifically AKTPL-001-4. Each of the projects must undergo further cost and benefit analysis prior to making the decision to construct each project. Some projects may be deemed feasible and constructed following the assessment and others may be put on hold until economic or other conditions warrant their construction.

All of the projects identified in the study are driven by the reliability improvements, with most having the added benefit of positive economic value. As the projects are evaluated going forward, the value of unserved energy, the value of renewable energy, the value of future load-serving capability, the value of capacity sharing or deferral and the value of a significant reduction in greenhouse gasses should be computed and utilized in each projects' analysis. However, some of the projects are strictly reliability driven projects with little or very small economic benefits and can only be justified by more traditional transmission evaluation methods.

A summary of the projects that have both economic and reliability benefits are included in Table 2.1.

*Table 2-1: Economic/Reliability Projects*

Priority	Project	Description	Cost (Millions)
1	Bernice Lake-Beluga HVDC	100 MW HVDC Intertie	\$ 185.3
2	35 MW/20 MWh BESS	Anchorage area battery	\$ 41.1
3	Bradley-Soldotna 115 kV Line	New line & Bradley/Soldotna sub	\$ 66.6
4	University-Dave's Creek 230kV	Reconstruct existing line	\$ 57.5
5	University-Dave's Substations	Convert line for 230 kV operation	\$ 36.3
6	Dave's Creek - Quartz Creek	Upgrade line to Rail conductor, Quartz sub	\$ 16.2
1	Lorraine-Douglas	Lorraine - Douglas 230 kV line/stations	\$ 128.5
2	Douglas - Healy line	New 230 kV line operated at 138 kV	\$ 245.7
1	Healy-Fairbanks 230 kV	Convert 138 kV to 230 kV	\$ 107.9
<b>Total Reliability &amp; Economic Projects</b>			<b>\$ 885.0</b>

Projects that do not include definitive economic benefits are shown in Table 2.2.

*Table 2-2: Reliability Projects*

Priority	Project	Description	Cost (Millions)
1	Fossil Creek	New 115 kV substation	\$ 11.9
3	Eklutna Hydro	New 115 kV substation	\$ 10.1
1	115 kV line	Plt 1-Raptor-Fssl Ck	\$ 17.3
1	Communications Upgrade	Communications between Anch-Fairbanks	\$ 15.0
<b>Total Reliability Only Projects</b>			<b>\$ 54.3</b>

The recommended transmission plan meets the requirements of AKTPL-001-4 for system reliability and contingency evaluation. However, AKTPL-001-4 also requires each project be evaluated in terms of reliability and costs to determine whether the project should be constructed. The evaluation required by the standard includes the costs identified in this report, but also requires the identification of all benefits, including the benefits not included in the scope of this

project, such as generation capacity deferral, value of unserved energy, water management, additional green energy, firm fuel and energy deliveries for all utilities, and Bradley excess energy delivery.

It is recognized that the costs included in this report are estimates and that changes in assumptions can alter the conclusions and recommendations.

---

### 3 Detailed Summary

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A detailed description of the projects and benefits for each of the Railbelt areas is presented below. The appendix includes detailed, itemized cost estimates for the projects recommended in this plan.

#### 3.1 Kenai- Anchorage Transmission

Transmission between the Kenai Peninsula and the rest of the Railbelt system consists of a single 115 kV transmission line to deliver power to, or receive power from, Southcentral Alaska. This line was completed in 1961 to transfer a relatively small amount of Cooper Lake Hydro power (16 MW) into the Anchorage area. The Bradley Lake Hydroelectric Project, commissioned in 1991, has been constrained in its operation since its completion due to the inadequate transmission system between the Kenai and the northern and southcentral Railbelt systems. In the past, the Bradley Lake project participants successfully mitigated the constraints of the transmission system to the greatest extent possible by cooperative agreements and actions among the utilities. The changing atmosphere of the Cook Inlet gas situation and the evolving landscape of generation in the Railbelt has foreclosed many of the mechanisms historically available to the Railbelt utilities to mitigate the constraints on the Bradley Lake project. As a result of the loss of the mitigation options and the changing aspects of the generation and gas systems, without improvements to the transmission system between Anchorage and Kenai, the utilities will experience substantial increases in both electrical line losses, lost generation capacity, and operating costs due to the transmission constraints placed on transfers from the Kenai.

In addition to the near-term constraints identified above, the Anchorage-Kenai constraints severely inhibit the integration of additional variable resources such as wind energy. These constraints prevent Kenai hydro energy from being used as part of an overall hydro management or coordination strategy to promote the integration of renewable energy. The lack of transmission capacity also limits the amount of other Kenai resources that could be used to mitigate the impacts of variable generation such as wind energy and will significantly increase the cost of integrating renewables into the Railbelt system. The Eklutna hydro facility is the only hydro resource not constrained by the Railbelt transmission system.

The basic constraint of the Bradley Lake project is the lack of an adequate transmission system to deliver the project's energy from Kachemak Bay to Anchorage and Fairbanks. Besides only a single transmission line between the Cooper Lake area and Anchorage, a single 115 kV transmission line from Soldotna to the Cooper Lake area makes up the connection between the majority of the Railbelt and Bradley Lake. These two single lines have a combined length of 146 miles. Although the lines have been well maintained and improved by the utility owners, they were not originally designed to carry large amounts of power over long distances. For comparison, the line between Anchorage and Fairbanks carries slightly less power than the University to Dave's Creek Line, but is constructed to a much higher voltage and uses two large conductors per phase instead of the one small conductor per phase, as used on the Kenai line.

The solution to eliminating the Bradley Lake constraints is an improved transmission system between Anchorage and the Kenai. This can be accomplished by either an additional transmission path between the two regions, upgrading the existing transmission line to a larger capacity line, or a combination of both building a new line and improving the existing line.

The study evaluated all three options. Adding a new transmission line between the regions greatly increases the reliability and relieves some constraints on Bradley Lake, but a new line by itself does not remove constraints on Bradley Lakes' energy, since Bradley Lake must be operated in a manner to continue operation following the loss of either the new or the existing transmission line. Upgrading the existing transmission line from Soldotna to Anchorage in lieu of a new line was also studied, however it was not recommended due to higher costs, construction timing, and constraints associated with continued operation of a transmission system with a single transmission line between Kenai and Anchorage.

The recommended transmission system is composed of improvements to portions of the existing Anchorage – Kenai transmission system, combined with a new transmission line connecting the Southcentral area's 230 kV transmission system at Beluga to the 115 kV transmission system at Bernice Lake or Soldotna. The combination of these two projects results in the lowest overall cost as well as the most benefits and fewest constraints on the Bradley project.

The routing of a new submarine cable and overhead transmission line were based on a paper study of possible routes using our past experience with the previously dismissed Southern Intertie. Other routing options that could reduce the cost of the line may be possible with further evaluation of the project.

In addition to the Bradley Lake constraints, the single contingency line between Anchorage and Kenai requires certain generators to operate on the Kenai. In order to ensure there is not excessive loss of load following the opening of the single transmission line, the Kenai is required to maintain certain levels of generation on-line as opposed to importing generation from other areas. As the generation fleet ages, this may require replacement of thermal units on the Kenai in a Railbelt system that is capacity rich in order to provide a base-loaded, more efficient unit to meet this generation constraint.

A 35 MW/20 MWhr BESS is recommended in conjunction with the transmission improvements. The project's primary purpose is to provide contingency reserves for the loss of the Kenai Intertie or HVDC line. However, it also provides benefits to the entire Railbelt area by supplying contingency reserves and some regulating reserves to the system. The size of the BESS, in conjunction with Hydro and other BESS resources can provide all the contingency reserves required in the Railbelt without thermal generation. The project could be located in any area north of the Kenai to provide these benefits.

A summary of the costs of the proposed projects to relieve the constraints on the Bradley Lake hydroelectric project and the Kenai generation constraints is presented in Table 3-1. The costs are estimated, budgetary figures within +/- 20%.

Table 3-1: Kenai Project Costs

Priority	Project	Description	Cost (Millions)
1	Bernice Lake-Beluga HVDC	100 MW HVDC Intertie	\$ 185.3
2	35 MW/20 MWh BESS	Anchorage area battery	\$ 41.1
3	Bradley-Soldotna 115 kV Line	New line & Bradley/Soldotna sub	\$ 66.6
4	University-Dave's Creek 230kV	Reconstruct existing line	\$ 57.5
5	University-Dave's Substations	Convert line for 230 kV operation	\$ 36.3
6	Dave's Creek - Quartz Creek	Upgrade line to Rail conductor	\$ 16.2
	Electrical Projects Total		\$ 403.0

### 3.2 Southcentral Alaska Reliability

A single 115 kV transmission line between the Anchorage and the Palmer areas connects AML&P's Plant 2 to the Eklutna Hydro Plant. A recent upgrade of this line has added a second circuit, which is not energized due to the lack of a substation at Fossil Creek and inadequate substation space at Eklutna. A portion of this new circuit is energized as a radial line from the EGS power plant. Improvements to the reliability of the Southcentral Railbelt system serving Anchorage and the Mat-Su area consist of two substation projects required to place this additional circuit into service. The substation projects are driven by reliability requirements. In the case of the Eklutna substation project, the existing substation equipment has exceeded its useful life and the station cannot be replaced in its current configuration.

The Fossil Creek Substation allows the interconnection of the second 115 kV transmission line into the Railbelt system and also allows for a second interconnection between the ML&P system and Fossil Creek through Raptor substation. This second path into the AML&P system eliminates generation constraints for the new Eklutna Generation Station and increases the critical clearing time for 115 kV faults to more manageable levels.

A second transmission line into the AML&P system via Raptor Substation increases reliability to the AML&P/JBER area and completes the path between the AML&P 115 kV and the 230 kV systems. This line segment is comprised of a Plant 1 – Raptor (7.0 Mi) section and a Raptor – Fossil Creel (4.1 Mi) section.

A summary of the costs of the proposed projects for the Southcentral Railbelt are presented in Table 3-2.

Table 3-2: Southcentral Project Costs

Priority	Station	Description	Costs (Millions)
1	Fossil Creek	New 115 kV substation	\$ 11.9
1	Eklutna Hydro	New 115 kV substation	\$ 10.1
1	115 kV line	Plt 1-Raptor-Fssl Ck	\$ 17.3
	Total		\$ 39.3

### 3.3 Anchorage-Fairbanks Intertie Reliability

Transfers between the Fairbanks area and the Anchorage/Kenai systems are currently limited to a single line between the areas. Due to the single line, all power transfers are "economic" or transfers that occur only when energy is available in the south through available generation and

when the single line is in service. GVEA currently maximizes the use of the existing intertie, but must maintain sufficient generation and fuel resources in its area in case the single intertie between is out of service. The absence of a second transmission line between the areas precludes the contracting for firm power between the Northern and Southern systems and precludes GVEA from contracting for known quantities of fuel or energy from the southern utilities including the sharing of capacity reserves across the Railbelt system.

The addition of a second line between Anchorage and Fairbanks increases the amount of energy capable of being transferred between the areas from 69 MW of non-firm in the existing system to over 189 MW of firm power sales with Healy 2 on-line (all of Fairbanks area load). It is important to note the difference in service between the existing system and the proposed system when comparing the improvements in transfer. Under the existing system, any transfer from Anchorage above 30-40 MW will result in load shedding in the Fairbanks area following the loss of the single line. This is considerably different than the 189 MW limit of the proposed system which would not result in any customer outages for the loss of a single line.

The second transmission line spanning the 171 miles between Healy and Anchorage will prevent loss of load in Fairbanks for single line outages and will allow GVEA to access electrical and gas markets in the Southcentral system. It will also allow GVEA to evaluate the most economic solution for replacement generation capacity as its power production fleet continues to age or if coal resources are retired.

A new substation approximately mid-way between Healy and Douglas substations is proposed to serve as a sectionalizing point between the line sections. The substation would lessen the impact of the loss of one of the two line section between Healy and Douglas, lessening the power swing due to the loss of the line. The substation also improves the voltage control characteristics and decreases the amount of required equipment needed for voltage control along the Douglas – Healy corridor.

A summary of the costs of the proposed projects to provide reliability and economic energy transfers between the northern and southern systems is presented in Table 3-3.

*Table 3-3: Northcentral Project Costs*

Group	Item	Description	Costs (Millions)
1	Lorraine-Douglas	Lorraine - Douglas 230 kV line/stations	\$ 128.5
2	Douglas – Healy line	New 230 kV line operated at 138 kV	\$ 245.7
	Communications Upgrade		\$ 15.0
	Total		\$ 389.1

The analysis determined that upgrading the 138 kV lines into the Fairbanks area to 230 kV essentially eliminated transfer constraints between southern generation resources and the Fairbanks area. An upgrade of the existing lines to 230 kV operation would satisfy the requirements of AKTPL-001-4 and increase the transfer capacity between the Anchorage and Fairbanks areas. The costs of the 230 kV transmission line upgrades are presented in Table 3-4.

Table 3-4: Northcentral Project Costs –230 kV Line Upgrades

Group	Item	Description	Cost (Millions)
1	Healy-Fairbanks 230 kV	Convert 138 kV to 230 kV	\$ 107.9

### 3.4 Proposed System Transmission Maps

Transmission maps were created for the proposed transmission system and are shown below in Figure 3-1: Northern Proposed Transmission System and Figure 3-2: Kenai and Southcentral Proposed Transmission System.

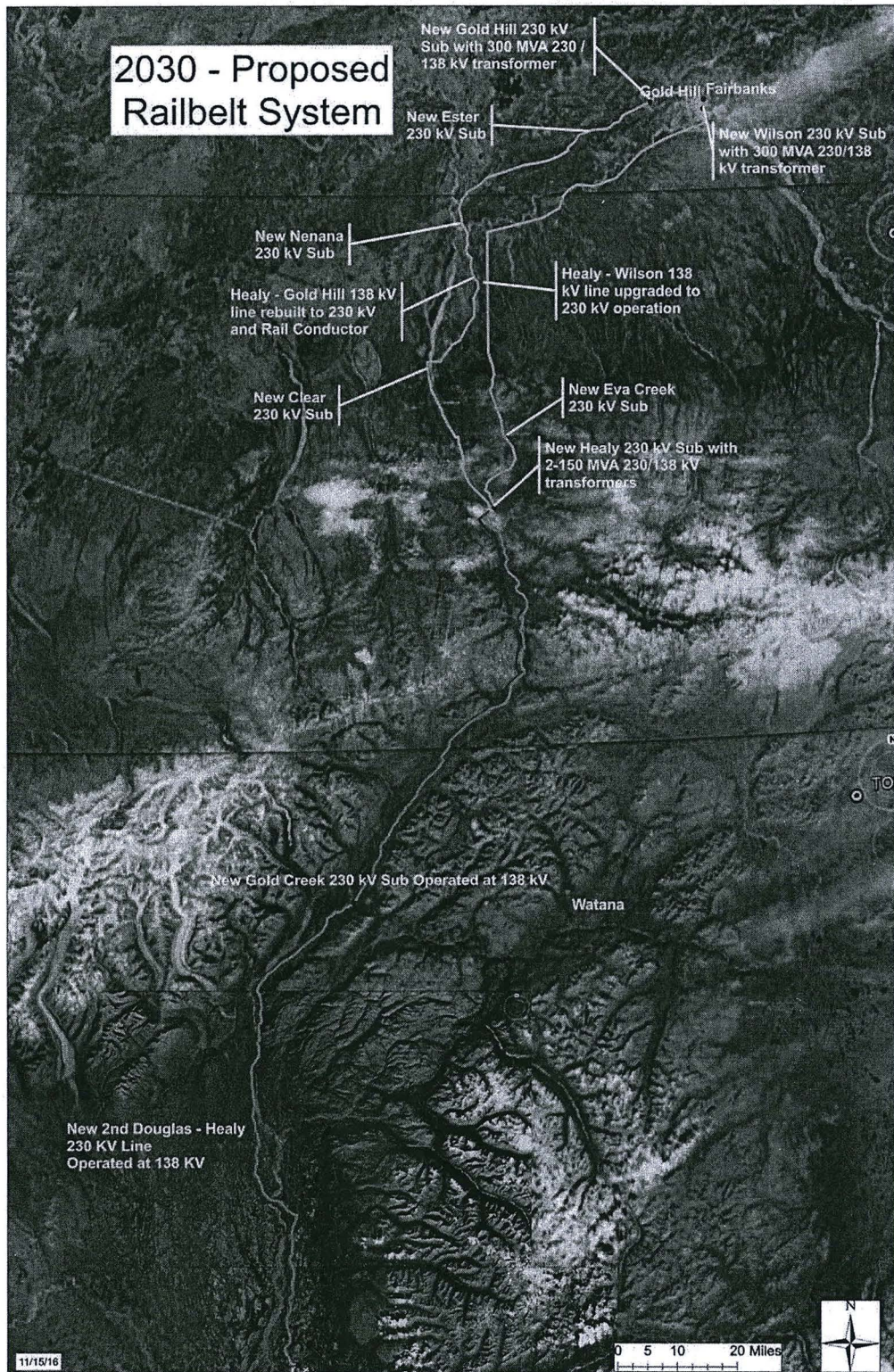


Figure 3-1: Northern Proposed Transmission System

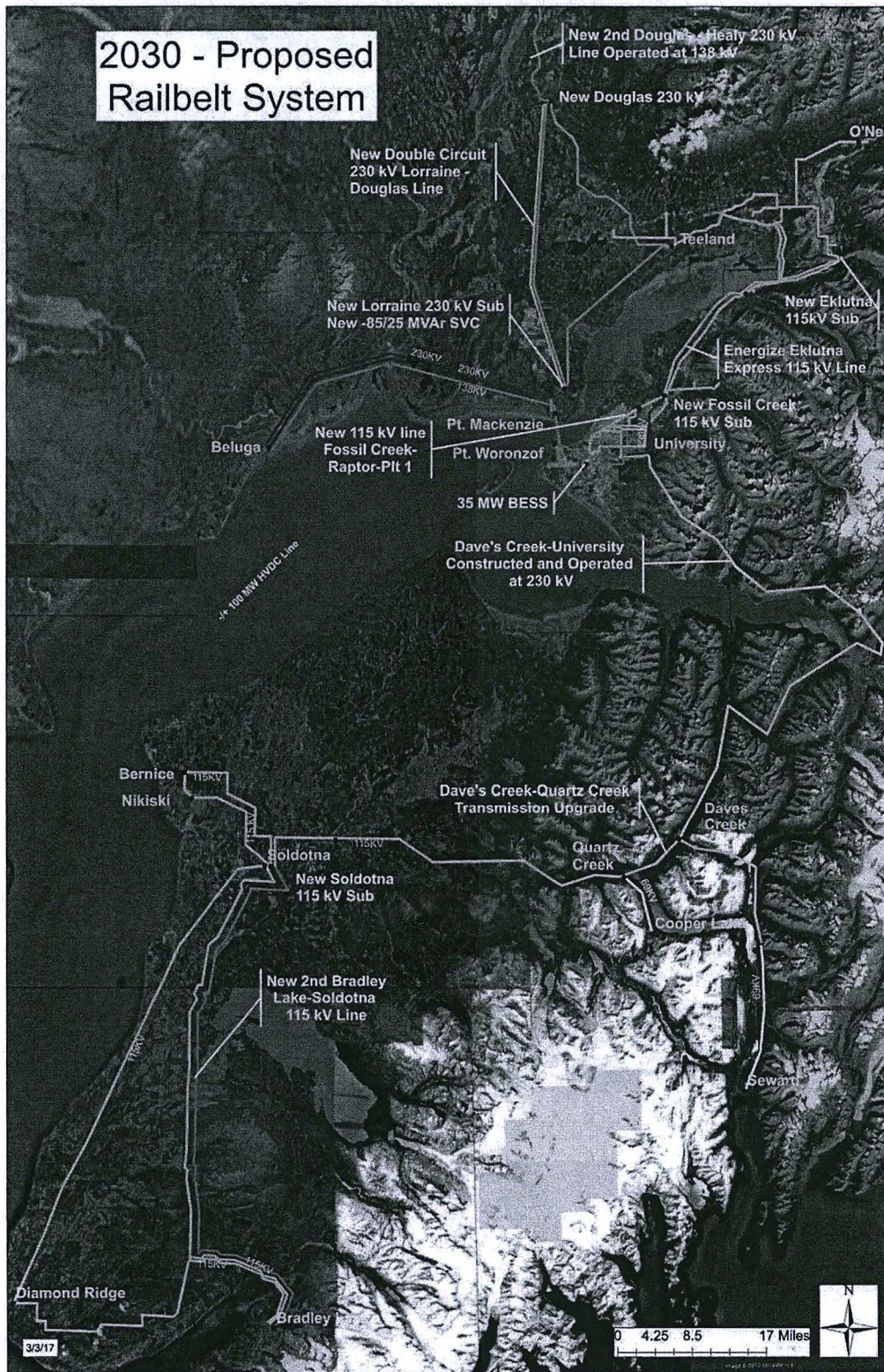
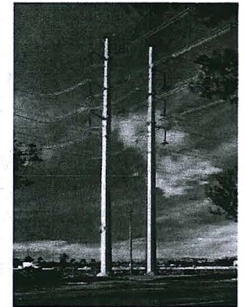
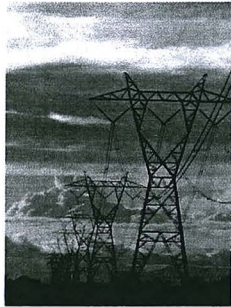


Figure 3-2: Kenai and Southcentral Proposed Transmission System

BUILDING A WORLD OF DIFFERENCE®



# Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study

Final Report

February 2010

## 1.0 EXECUTIVE SUMMARY

In response to a directive from the Alaska Legislature, the Alaska Energy Authority (AEA) was the lead State agency for the development of a Regional Integrated Resource Plan (RIRP) for the Railbelt Region. This region is defined as the service areas of six regulated public utilities, including: Anchorage Municipal Light & Power (ML&P), Chugach Electric Association (Chugach), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), Matanuska Electric Association (MEA), and the City of Seward Electric System (SES). A seventh utility, Doyon, is interconnected to the Railbelt system serving the military bases of Fort Greely, Fort Wainwright, and Fort Richardson, but is not included in this RIRP.

The purpose of this document is to provide the results of the RIRP study. This section includes the following subsections:

- Current Situation Facing the Railbelt Utilities
- Project Overview
- Evaluation Scenarios
- Summary of Key Input Assumptions
- Susitna Analysis
- Transmission Analysis
- Summary of Results
- Implementation Risks and Issues
- Conclusions and Recommendations
- Near-Term Implementation Plan (2010-2012)

### Some Definitions

- **REGA** means "Railbelt Electrical Grid Authority"
- **GRETC** means "Greater Railbelt Energy & Transmission Company"
- **RIRP** means "Railbelt Integrated Resource Plan"

### Three Discrete Tasks

- **REGA study** determined the business structure for future Railbelt generation and transmission (G&T)
- **GRETC initiative** is the joint effort between Railbelt Utilities and AEA to unify Railbelt G&T
- **RIRP** is the economic plan for future capital investment in G&T and in fuel portfolios that GRETC would build, own and operate

### 1.1 Current Situation Facing the Railbelt Utilities

The Railbelt generation, transmission, and distribution infrastructure did not exist prior to the 1940s. At that time, citizens in separate areas within the Railbelt region joined together to form four cooperatives (Chugach, GVEA, HEA, and MEA) and two municipal utilities (ML&P and SES) to provide electric power to the consumers and businesses within their service areas. Collectively, these utilities are referred to as the Railbelt utilities.

The independent and cooperative decisions made over time by utility managers and Boards, as well as the State, in a number of areas have significantly improved the quality of life and business environment in the Railbelt. Examples include:

- **Infrastructure Investments** – the State and the Railbelt utilities have made significant investments in the region’s generation and transmission infrastructure. Examples include the Alaska Intertie and Bradley Lake Hydroelectric Plant.
- **Gas Supply Investments and Contracts** – ML&P took a bold step when it purchased a portion of the Beluga River Gas Field, a decision that has produced a significant long-term benefit for ML&P’s customers and others within the Railbelt. Additionally, Chugach was able to enter into attractive gas supply contracts. These decisions have resulted in historical low gas prices which have significantly offset the region’s inability to achieve economies of scale in generation due to its small size.
- **Innovative Solutions** – GVEA’s Battery Energy Storage System (BESS) is one example of numerous innovative decisions that have been made by utility managers and Boards to address issues that are unique to the Railbelt region.
- **Joint Operations and Contractual Arrangements** – over the years, the Railbelt utilities have joined together for joint benefit in terms of coordinated operation of the Railbelt transmission grid and have entered into contractual arrangements that have benefited each utility.

The evolution of the business and operating environment, and changes in the mix of stakeholders, presents new dynamics for the way decisions must be made. This changing environment poses significant challenges for the Railbelt utilities and, indeed, all stakeholders. In fact, it is not an overstatement to say that the Railbelt is at a historical crossroad, not unlike the period of time when the Railbelt utilities were originally formed.

Categories of issues facing the Railbelt utilities include:

- Uniqueness of the Railbelt region
- Cost issues
- Natural gas issues
- Load uncertainties
- Infrastructure issues
- Future resource options
- Political issues
- Risk management issues

### **Current Situation**

- Limited redundancy
- Limited economies of scale
- Dependence on fossil fuels
- Limited Cook Inlet gas deliverability and storage
- Aging G&T infrastructure
- Inefficient fuel use
- Difficult financing
- Duplicative G&T expertise

Table 1-1 provides a listing of the issues within each of these categories. A detailed discussion of these issues is provided in **Section 3**.

**Table 1-1  
Summary Listing of Issues Facing the Railbelt Region**

<p><b>Uniqueness of the Railbelt Region</b></p> <ul style="list-style-type: none"> <li>• Size and geographic expanse</li> <li>• Limited interconnections and redundancies</li> </ul>	<p><b>Load Uncertainties</b></p> <ul style="list-style-type: none"> <li>• Stable native growth</li> <li>• Potential major new loads</li> </ul>	<p><b>Political Issues</b></p> <ul style="list-style-type: none"> <li>• Historical dependence on State funding</li> <li>• Proper role for State</li> </ul>
<p><b>Cost Issues</b></p> <ul style="list-style-type: none"> <li>• Relative costs – Railbelt region versus other states</li> <li>• Relative costs – among Railbelt utilities</li> <li>• Economies of scale</li> </ul>	<p><b>Infrastructure Issues</b></p> <ul style="list-style-type: none"> <li>• Aging generation infrastructure</li> <li>• Baseload usage of inefficient generation facilities</li> <li>• Operating and spinning reserve requirements</li> </ul>	<p><b>Risk Management Issues</b></p> <ul style="list-style-type: none"> <li>• Need to maintain flexibility</li> <li>• Future fuel diversity</li> <li>• Aging infrastructure</li> <li>• Ability to spread regional risks</li> </ul>
<p><b>Natural Gas Issues</b></p> <ul style="list-style-type: none"> <li>• Historical dependence</li> <li>• Expiring contracts</li> <li>• Declining developed reserves and deliverability</li> <li>• Historical increase in gas prices</li> <li>• Potential gas supplies and prices</li> </ul>	<p><b>Future Resource Options</b></p> <ul style="list-style-type: none"> <li>• Acceptability of large hydro and coal</li> <li>• Carbon tax and other environmental restrictions</li> <li>• Optimal size and location of new generation and transmission facilities</li> <li>• Limited development – renewables</li> <li>• Limited development – demand-side management/energy efficiency (DSM/EE) programs</li> </ul>	

**1.2 Project Overview**

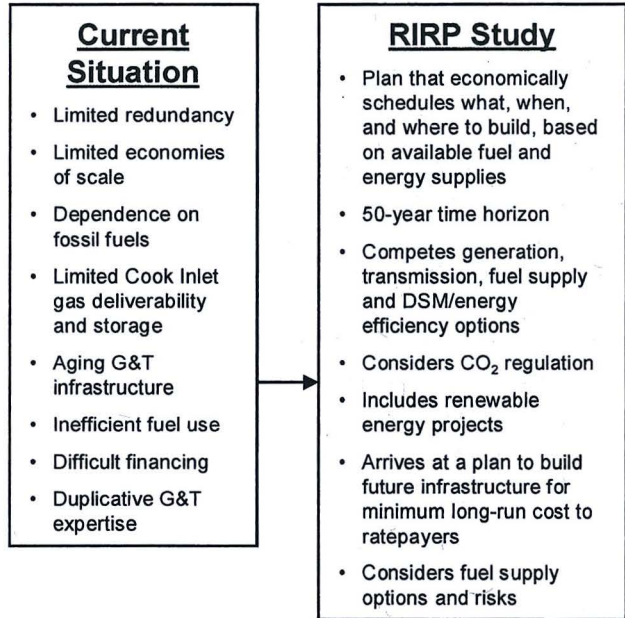
The goal of this project is to minimize future power supply costs, and maintain or improve on current levels of power supply reliability, through the development of a single comprehensive RIRP for the Railbelt region. The intent of the RIRP project, as stated in the AEA request-for-proposal, is to provide:

- An up-to-date model that the utilities and AEA can use as a common database and model for future planning studies and analysis.
- An assessment of loads and demands for the Railbelt electrical grid for a time horizon of 50 years including new potential industrial demands.
- Projections for Railbelt electrical capacity and energy growth, fuel prices, and resource options.
- An analysis of the range of potential generation resources available, including costs, construction schedule, and long-term operating costs.

**RIRP Objective Function**

Minimize regional power supply costs, and maintain or improve current reliability, as opposed to minimizing power supply costs for any individual utility.

- A schedule for existing generating unit retirement, new generation construction, and construction of backbone transmission lines that will allow the future Railbelt electrical grid to operate reliably under a transmission tariff which allows access by all potential power producers, and with a postage-stamp rate for electric energy and demand for the entire Railbelt as a whole.
- A long-term schedule for developing new fuel supplies that will provide for reliable, stable priced electrical energy for a 50-year planning horizon.
- A short-term schedule that coordinates immediate network needs (i.e., increasing penetration level of non-dispatchable generation, such as wind) within the first 10 years of the planning horizon, consistent with the long-term goals.
- A short-term plan addressing the transition from the present decentralized ownership and control to a unified G&T entity that identifies unified actions between utilities that must occur during this transition period.
- A diverse portfolio of power supply that includes, in appropriate portions, renewable and alternative energy projects and fossil fuel projects, some or all of which could be provided by independent power producers (IPPs).
- A comprehensive list of current and future generation and transmission power infrastructure projects.



The alternative resource options considered in the RIRP analysis are shown in Table 1-2.

Black & Veatch conducted the REGA study for the AEA and the final report was released in September 2008. That study evaluated the feasibility of the Railbelt utilities forming an organization to provide coordinated unit commitment and economic dispatch of the region’s generation resources, generation and transmission system planning, and project development. As a result of that study, legislation was proposed to create GRETC with a 10-year transition period to achieve these goals. This RIRP is based on the GRETC concept being implemented from the beginning of the study’s time horizon.

Black & Veatch had primary responsibility for conducting this Railbelt RIRP. In addition to Black & Veatch, three other AEA contractors (HDR Inc., Electric Power Systems, Inc., and Seattle-Northwest Securities Corporation) played important roles in the development of the RIRP.

HDR updated work from the mid-1980s on the Susitna Hydroelectric Project and developed the capital and operating costs, as well as the generating characteristics, for several smaller-sized Susitna projects. HDR’s work was used by Black & Veatch in the Strategist® and PROMOD® modeling discussed below. HDR’s report summarizing the results of its work is provided in **Appendix A**.

Electric Power Systems, Inc. (EPS) assisted in the evaluation of the region’s transmission system.

**Table 1-2  
Alternative Resource Options Considered**

Demand-Side Management/Energy Efficiency (DSM/EE) Measure Categories	Conventional Generation Resources	Renewable Resources
<p><b>Residential</b></p> <ul style="list-style-type: none"> <li>• Appliances</li> <li>• Water Heating</li> <li>• Lighting</li> <li>• Shell</li> <li>• Cooling/Heating</li> </ul> <p><b>Commercial</b></p> <ul style="list-style-type: none"> <li>• Water Heating</li> <li>• Office Loads</li> <li>• Motors</li> <li>• Lighting</li> <li>• Refrigeration</li> <li>• Cooling/Heating</li> </ul>	<p><b>Simple Cycle Combustion Turbines</b></p> <ul style="list-style-type: none"> <li>• LM6000 (48 MW)</li> <li>• LMS100 (96 MW)</li> </ul> <p><b>Combined Cycle</b></p> <ul style="list-style-type: none"> <li>• 1x1 6FA (154 MW)</li> <li>• 2X1 6FA (310 MW)</li> </ul> <p><b>Coal Units</b></p> <ul style="list-style-type: none"> <li>• Healy Clean Coal</li> <li>• Generic – 130 MW</li> </ul>	<p><b>Hydroelectric Projects</b></p> <ul style="list-style-type: none"> <li>• Susitna</li> <li>• Chakachamna</li> <li>• Glacier Fork</li> <li>• Generic Hydro – Kenai</li> <li>• Generic Hydro - MEA</li> </ul> <p><b>Wind</b></p> <ul style="list-style-type: none"> <li>• BQ Energy/Nikiski</li> <li>• Fire Island</li> <li>• Generic Wind – Kenai</li> <li>• Generic Wind - GVEA</li> </ul> <p><b>Geothermal</b></p> <ul style="list-style-type: none"> <li>• Mt. Spurr</li> </ul> <p><b>Municipal Solid Waste</b></p> <ul style="list-style-type: none"> <li>• Generic – Anchorage</li> <li>• Generic - GVEA</li> </ul>
<p><b>Other Resources Included in Sensitivity Cases</b></p> <ul style="list-style-type: none"> <li>• Modular Nuclear</li> <li>• Tidal</li> </ul>		

Seattle-Northwest Securities Corporation (SNW) developed the financial model used to determine the overall financing costs for the portfolio of generation and transmission projects developed as part of this project, and evaluated the impact of some financial options that could be used to address financing issues and mitigating related rate impacts. The results of SNW’s analysis are provided in **Appendix B**.

Additional information regarding Black & Veatch’s approach to the completion of this study is provided in **Section 2**.

### *Purpose and Limitations of the RIRP*

- The development of this RIRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor and State Legislature. With regard to energy policy making, however, the RIRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

Having said this, the development of a State Energy Policy and or related policies could directly impact the specific alternative resource plan chosen for the Railbelt region's future. As such, the RIRP may need to be readdressed as future energy-related policies are enacted.

- This RIRP, consistent with all integrated resource plans, should be viewed as a "directional" plan. In this sense, the RIRP identifies alternative resource paths that the region can take to meet the future electric needs of Railbelt citizens and businesses; in other words, it identifies the types of resources that should be developed in the future. The granularity of the analysis underlying the RIRP is not sufficient to identify the optimal configuration (e.g., specific size, manufacturer, model, location, etc.) of specific resources that should be developed. The selection of specific resources requires additional and more detailed analysis.
- The alternative resource options considered in this study include a combination of identified projects (e.g., Susitna and Chakachamna hydroelectric projects, Mt. Spurr geothermal project, etc.), as well as generic resources (e.g., Generic Hydro – Kenai, Generic Wind – GVEA, generic conventional generation alternatives, etc.). Identified projects are included, and shown as such, because they are projects that are currently at various points in the project development lifecycle. Consequently, there is specific capital cost and operating assumptions available on these projects. Generic resources are included to enable the RIRP models to choose various resource types, based on capital cost and operating assumptions developed by Black & Veatch. This approach is common in the development of integrated resource plans.

Consistent with the comment above regarding the RIRP being a "directional" plan, the actual resources developed in the future, while consistent with the resource type identified, may be: 1) the identified project shown in the resource plan (e.g., Chakachamna), 2) an alternative identified project of the same resource type (e.g., Susitna); or 3) an alternative generic project of the same resource type. One reason for this is the level of risks and uncertainties that exist regarding the ability to plan, permit, and develop each project. Consequently, when looking at the resource plans shown in this report, it is important to focus on the resource type of an identified resource, as opposed to the specific project.

- The capital costs and operating assumptions used in this study for alternative DSM/EE, generation and transmission resources do not consider the actual owner or developer of these resources. Ownership could be in the form of individual Railbelt utilities, a regional entity, or an independent power producer (IPP). Depending upon specific circumstances, ownership and development by IPPs may be the least-cost alternative.
- As with all integrated resource plans, this RIRP should be periodically updated (e.g., every three years) to identify changes that should be made to the preferred resource plan to reflect changing circumstances (e.g., resolution of uncertainties), improved cost and performance of emerging technologies (e.g., tidal), and other developments.

**1.3 Evaluation Scenarios**

Black & Veatch, in collaboration with the Advisory Working Group that was assembled by the AEA for this project, developed four Evaluation Scenarios; Black & Veatch then developed a 50-year resource plan for each of these Evaluation Scenarios.

The primary objective of these Evaluation Scenarios was to evaluate two key drivers. The first driver was to look at what the impacts would be if the demand in the region was significantly greater than it is today; of primary interest was to see if higher demands would result in greater reliance on large generation resource options and allow for more aggressive expansion of the region’s transmission network.

The second driver was to determine the impact associated with the pursuit of a significant amount of renewable resources over the 50-year time horizon.

As a result, Black & Veatch evaluated the four Evaluation Scenarios shown in Figure 1-1.

**Figure 1-1  
Evaluation Scenarios**

<b>Load Forecast</b>	<b>Base Case</b>	<b>Scenario 1A</b>	<b>Scenario 1B</b>
	<b>High Growth Case</b>	<b>Scenario 2A</b>	<b>Scenario 2B</b>
		<b>Least Cost</b>	<b>Force 50%</b>
<b>Level of Renewables by 2025 (Energy)</b>			

The key assumptions underlying each Evaluation Scenario include:

- **Scenario 1 – Base Case Load Forecast**
  - Current regional loads with projected growth
  - All available resources – fossil fuel, renewables, and DSM/EE
  - Probabilistic estimate of gas supply availability and prices
  - Deterministic price forecasts for other fossil fuels
  - Emissions including CO<sub>2</sub> costs
  - Transmission system investments required to support selected resources
  - **Scenario 1A – Least Cost Plan**
  - **Scenario 1B – Force 50% Renewables**

- **Scenario 2 – Large Growth Load Forecast**
  - Significant growth in regional loads due to economic development efforts or large scale electrification (e.g., economic development loads, space and water heating fuel switching, and electric vehicles)
  - Base case resources, fuel availability/price forecasts and CO<sub>2</sub> costs
  - Transmission system investments required to support selected resources
  - **Scenario 2A – Least Cost Plan**
  - **Scenario 2B – Force 50% Renewables**

#### 1.4 Summary of Key Input Assumptions

The completion of this RIRP required the development of a large number of assumptions in the following categories:

- **Section 4 – Description of Existing System**, including information on existing generation resources, committed generation resources, and the existing Railbelt transmission network.
- **Section 5 – Economic Parameters**, including inflation rates, financing rates, present worth discount rate, interest during construction rate, and fixed charge rates.
- **Section 6 – Forecast of Electrical Demand and Consumption**, including 50-year peak demand forecasts and net energy for load requirements.
- **Section 7 – Fuel and Emissions Allowance Price Projections**, including price forecasts for various fuels and emission allowance price projections.
- **Section 8 – Reliability Criteria**, including the region's planning and operating reserve margin requirements.
- **Section 9 – Capacity Requirements**, including the region's capacity requirements over the 50-year planning horizon.
- **Section 10 – Supply-Side Options**, including an overview of the supply-side resource option input assumptions used in this study, including both conventional technologies and renewable energy options.
- **Section 11 – DSM/EE Resources**, including a summary of the methodology and assumptions that Black & Veatch used to evaluate potential DSM/EE measures.
- **Section 12 – Transmission Projects**, including an overview of the transmission projects required to improve the overall reliability of the region's transmission network and connect the generation resources included in the alternative resource plans that were developed as part of this project.

#### 1.5 Susitna Analysis

A hydroelectric project on the Susitna River has been studied for more than 50 years and is again being considered by the State of Alaska as a long term source of energy. In the 1980s, the project was studied extensively by the Alaska Power Authority (APA) and a license application was submitted to the Federal Energy Regulatory Commission (FERC). Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986.

In 2008, the Alaska State Legislature authorized the AEA to perform an update of the project. That authorization also included this RIRP project to evaluate the ability of this project and other sources of energy to meet the long term energy demand for the Railbelt region of Alaska. Of all the hydro projects in the Railbelt region, the Susitna projects are the most advanced and best understood.

HDR was contracted by AEA to update the cost estimate, energy estimates and the project development schedule for a Susitna River hydroelectric project. The initial alternatives reviewed were based upon the 1983 FERC license application and subsequent 1985 amendment which presented several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 MW.
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.
- **Devil Canyon.** This alternative consists of the construction of a 646-foot-high concrete dam at the Devil Canyon site with a four-unit powerhouse with a total installed capacity of 680 MW.
- **Watana/Devil Canyon.** This alternative consists of the full-height Watana development and the Devil Canyon development as presented in the 1983 FERC license application. The two dams and powerhouses would be constructed sequentially without delays. The combined Watana/Devil Canyon development would have a total installed capacity of 1,880 MW.
- **Staged Watana/Devil Canyon.** This alternative consists of the Watana development constructed in stages and the Devil Canyon development as presented in the 1985 FERC amendment. In stage one the Watana dam would be constructed to the lower height and the Watana powerhouse would only have four out of the six turbine generators installed, but would be constructed to the full sized powerhouse. In stage two the Devil Canyon dam and powerhouse would be constructed. In stage three the Watana dam would be raised to its full height, the existing turbines upgraded for the higher head, and the remaining two units installed. At completion, the project would have a total installed capacity of 1,880 MW.

As the RIRP process defined the future Railbelt power requirement it became evident that lower cost hydroelectric project alternatives, that were a closer fit to the energy needs of the Railbelt, should be sought.

As such, the following single dam configurations were also evaluated:

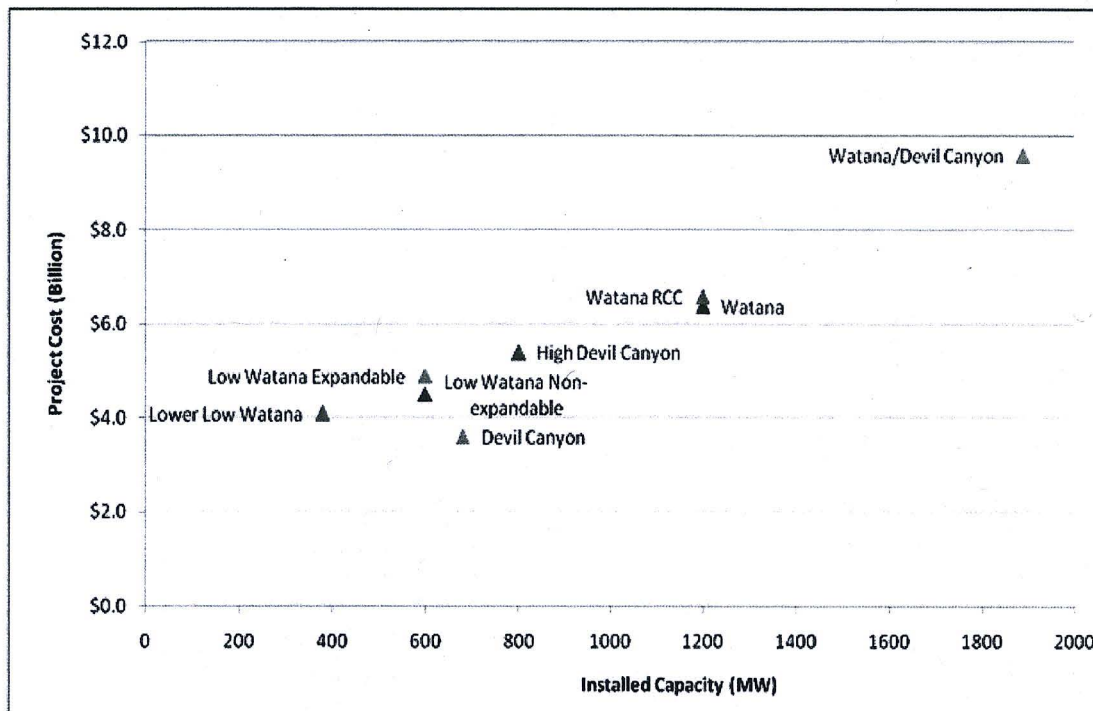
- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing four turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative consists of the Watana dam constructed to a height of 650 feet along with a powerhouse containing three turbines with a total installed capacity of 380 MW. This alternative has no provisions for future expansion.
- **High Devil Canyon.** This alternative consists of a roller-compacted concrete (RCC) dam constructed to a height of 810 feet, along with a powerhouse containing four turbines with a total installed capacity of 800 MW.
- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing six turbines with a total installed capacity of 1,200 MW.

The results of this study are summarized in Table 1-3 and a comparison of project size versus project cost is shown in Figure 1-2.

**Table 1-3  
Susitna Summary**

Alternative	Dam Type	Dam Height (feet)	Ultimate Capacity (MW)	Firm Capacity, 98% (MW)	2008 Construction Cost (\$ Billion)	Energy (GWh/yr)	Schedule (Years from Start of Licensing)
Lower Low Watana	Rockfill	650	380	170	\$4.1	2,100	13-14
Low Watana Non-expandable	Rockfill	700	600	245	\$4.5	2,600	14-15
Low Watana Expandable	Rockfill	700	600	245	\$4.9	2,600	14-15
Watana	Rockfill	885	1,200	380	\$6.4	3,600	15-16
Watana RCC	RCC	885	1,200	380	\$6.6	3,600	15-16
Devil Canyon	Concrete Arch	646	680	75	\$3.6	2,700	14-15
High Devil Canyon	RCC	810	800	345	\$5.4	3,900	13-14
Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	\$9.6	7,200	15-20
Staged Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	\$10.0	7,200	15-24

**Figure 1-2**  
**Comparison of Project Cost Versus Installed Capacity**



In all cases, the ability to store water increases the firm capacity over the winter. Projects developed with dams in series allow the water to be used twice. However, because of their locations on the Susitna River, not all projects can be combined. The Devil Canyon site precludes development of the High Devil Canyon site but works well with Watana. The High Devil Canyon site precludes development of Watana but could potentially be paired with other sites located further upstream.

The detailed results of the HDR Susitna study, except for the detailed appendices, are provided in **Appendix A**. One of the appendices contained within the HDR report (Appendix D), which is not included in Appendix A of this report, addresses the issue of the potential impact of climatic changes on Susitna's resource potential; this appendix can be viewed in the full HDR report which is available on the AEA web site.

### 1.6 Transmission Analysis

An important element of this RIRP was the analysis of transmission investments required to integrate the generation resources in each resource plan, ensure reliability and enable the region to take advantage of economy energy transfers between load areas within the region.

The fundamental objective underlying the transmission analysis was to upgrade the transmission system over a 10-year period to remove transmission constraints that currently prevent the coordinated operation of all the utilities as a single entity.

The study included all assets 69 kV and above. These assets, over a transition period, may flow into GRETC and form the basis for a phased upgrade of the system into a robust, reliable transmission system that can accommodate the economic operation of the interconnected system. The transmission analysis also assumed that all utilities would participate in GRETC with planning being conducted on a GRETC (i.e., regional) basis. The common goal would be the tight integration of the system operated by GRETC.

Potential transmission investments in each of the following four categories were considered:

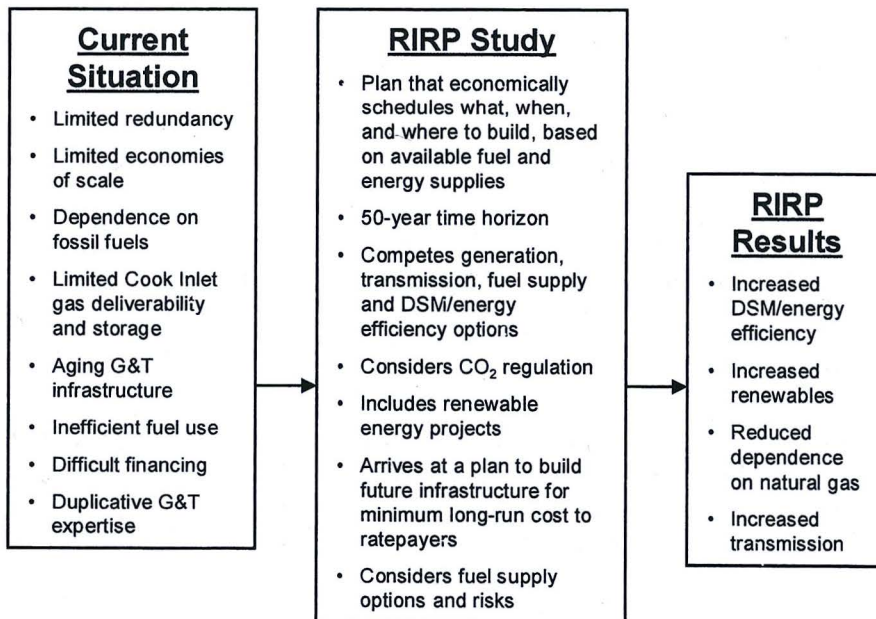
- Transmission systems that need to be replaced because of age and condition (Category 1)
- Transmission projects required to improve grid reliability, power transfer capability, and reserve sharing (Category 2)
- Transmission projects required to connect new generation projects to the grid (Category 3)
- Transmission projects to upgrade the grid required by a new generation project (Category 4)

In developing the transmission system, reliability remains a significant focus. Redundancy is one way to increase reliability, but may not be the only way to improve or maintain reliability.

The results of Black & Veatch’s transmission assessment are discussed later in this section.

**1.7 Summary of Results**

The purpose of this subsection is to summarize the results of the RIRP analysis. We begin by providing a summary of the base case results for each of the four Evaluation Scenarios. We then provide a comparative summary of the economic and emission results for all base cases and sensitivity cases. This is followed by a summary of the results of the transmission analysis that was completed and, finally, the results of the financial analysis. More detailed information regarding the results of the RIRP study is provided in Section 13.



### 1.7.1 Results of Reference Cases

In this subsection, we provide summaries of the reference case results for each of the following four Evaluation Scenarios:

- Scenario 1A – Base Case Load Forecast – Least Cost Plan
- Scenario 1B - Base Case Load Forecast – Force 50% Renewables
- Scenario 2A – Large Growth Load Forecast – Least Cost Plan
- Scenario 2B - Large Growth Load Forecast – Force 50% Renewables

Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built. Hereafter, we will refer to Scenarios 1A and 1B together.

We begin with a summary of the impact that DSM/EE measures have on the region's capacity and annual energy requirements. This is followed by summary graphics and information for each of the Evaluation Scenarios. Detailed model output for each of the reference cases are provided in **Appendices E-G**.

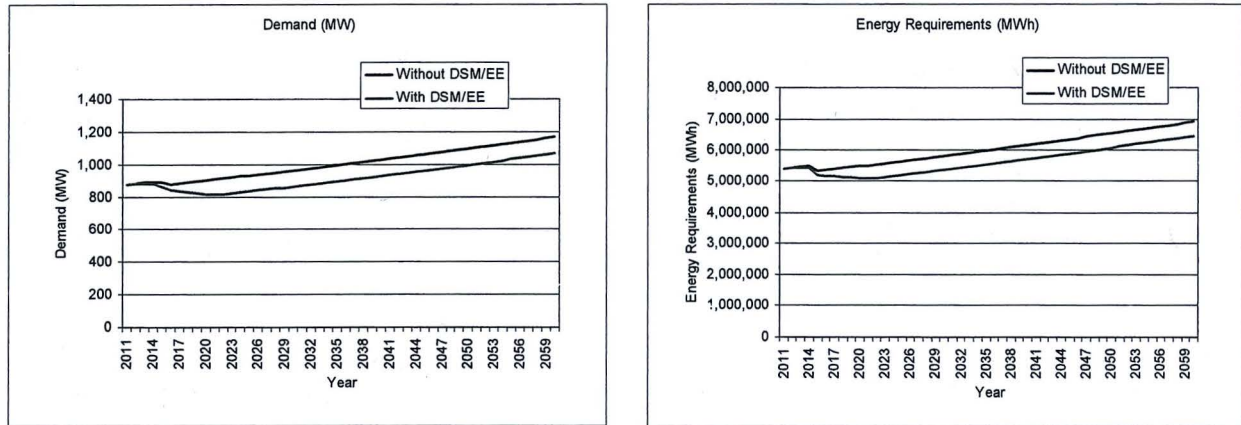
#### 1.7.1.1 DSM/EE Resources

As discussed in **Section 11**, Black & Veatch screened a broad array of residential and commercial DSM/EE measures. Based on this screening, 21 residential and 51 commercial DSM/EE measures were selected for inclusion in the RIRP models, Strategist<sup>®</sup> and PROMOD<sup>®</sup>, as potential resources to be selected.

Based upon the relative economics and savings of these screened residential and commercial DSM/EE measures, from the utility perspective, all of the residential and commercial DSM/EE measures were selected in each of the four Evaluation Scenarios. As discussed in **Section 11**, the penetration of the measures was based on technology adoption curves for DSM/EE studies from the BASS model; additionally, DSM/EE measures are treated by Strategist<sup>®</sup> and PROMOD<sup>®</sup> as a reduction to the load forecast from which the alternative supply-side options are considered for adding generation resources.

As can be seen in Figure 1-3, DSM/EE measures result in a significant impact on the region's capacity and energy requirements. After the initial program start-up years, DSM/EE measures reduce the region's capacity requirements by approximately 8 percent. A similar level of impact is also shown for annual energy requirements.

**Figure 1-3**  
**Impact of DSM/EE Resources – Base Case Load Forecast**



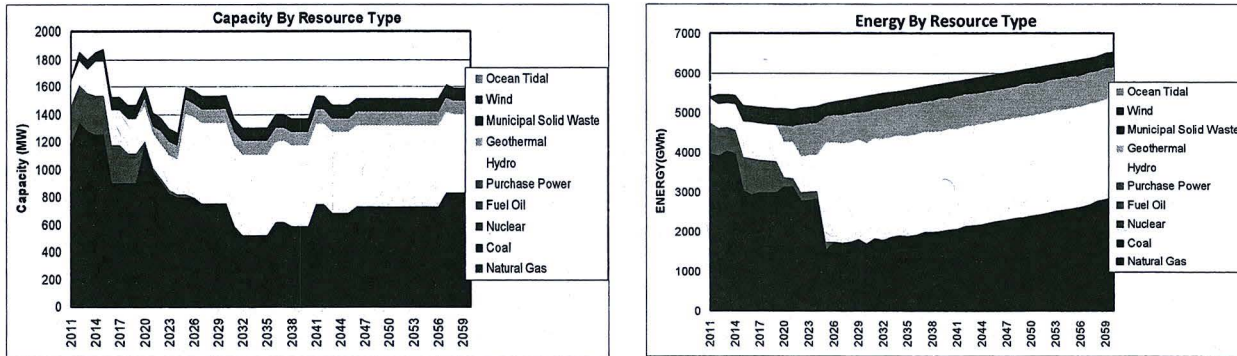
It should be noted that this study did not include an evaluation of innovative rate designs (e.g., real-time pricing and demand response rates), nor did it consider the potential benefits of a Smart Grid, and the associated widespread implementation of smart meters. These options could result in even greater reductions in peak demand and annual energy usage.

#### A Note Regarding DSM/EE Resources

- This RIRP demonstrates the economic potential of DSM/EE resources.
- Due to limited Alaska-specific DSM/EE-related data and experience, Black & Veatch limited the amount of DSM/EE resources included in the preferred resource plan.
- Additional analysis, both by Black & Veatch as part of this study and by others, along with the experience of other utilities throughout the US, suggest that additional levels of DSM/EE resources may be economic.
- However, given the lack of Alaska-specific data and experience, additional data gathering and analysis is required before the optimal level of DSM/EE resources can be determined.
- Furthermore, the isolated nature of the Railbelt coupled with severe weather conditions, dictates caution with regard to the ultimate reliance on DSM/EE resources.
- Additionally, the limited penetration of electric space heating in the Railbelt region affects the ultimate level of DSM/EE savings.
- To develop the full potential of DSM/EE resources, it will be necessary to collect baseline end-use saturation, customer and vendor information, as well as address the reduction in utility margins that result from the implementation of DSM/EE programs.
- Additionally, Black & Veatch believes that a regional approach to the development of DSM/EE programs (e.g., GRETC) will be more successful than if the six Railbelt utilities develop independent DSM/EE programs.

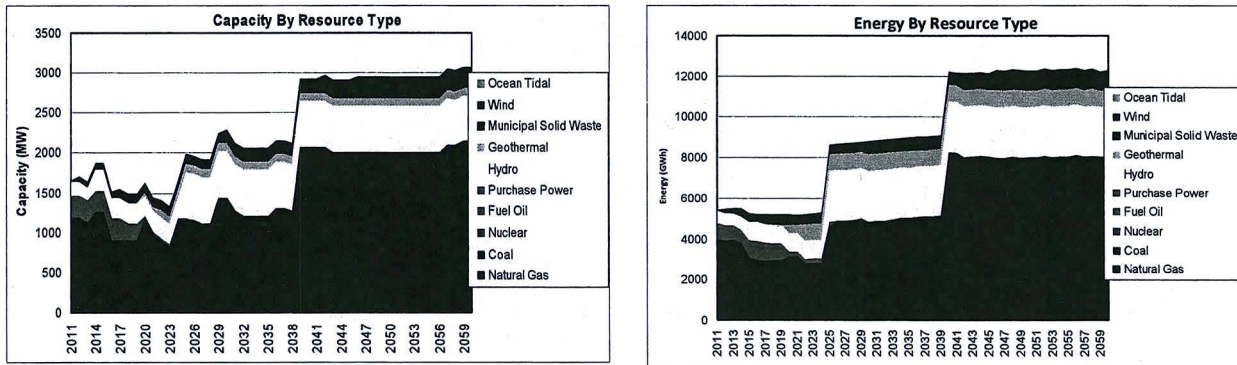
1.7.1.2 Results – Scenarios 1A/1B Reference Cases

Figure 1-4  
Results – Scenarios 1A/1B Reference Cases



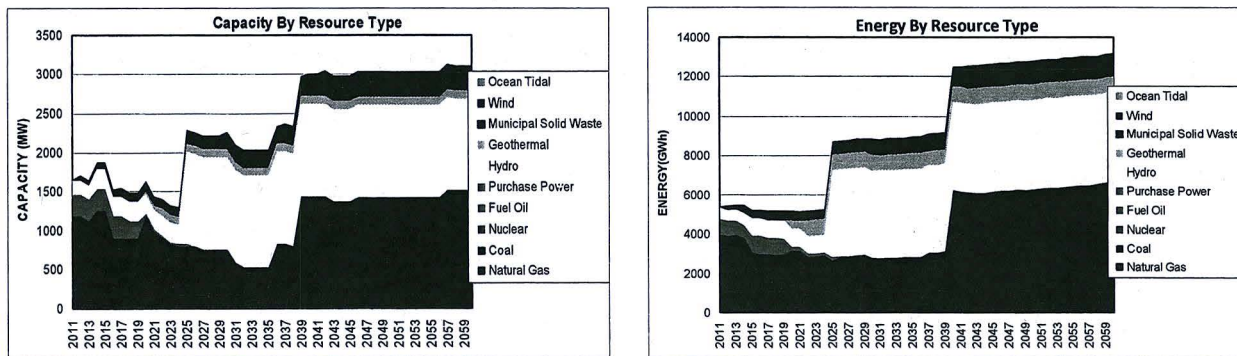
1.7.1.3 Results – Scenario 2A Reference Case

Figure 1-5  
Results – Scenario 2A Reference Case



1.7.1.4 Results – Scenario 2B Reference Case

Figure 1-6  
Results – Scenario 2B Reference Case



#### **A Note Regarding Emerging Technologies**

- In the economic analysis underlying this RIRP, Black & Veatch used current cost and performance assumptions for all generation technology options considered. This was done because of the inherent difficulty in predicting the future cost and performance of technologies, particularly emerging technologies (e.g., on-shore and off-shore wind and tidal).
- Recent improvements in wind-related costs and performance demonstrate the potential for emerging technologies. Conversely, the cost and performance of conventional resource technologies are stable at best and not likely to improve.
- Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to become economic within the planning horizon.
- These diverging cost and performance trends are one reason why this RIRP needs to be updated periodically; by so doing, emerging technologies can be added to the region's preferred resource plan as their costs and performance improve.

### **1.7.2 Sensitivity Cases Evaluated**

The following sensitivity cases were evaluated:

- Scenarios 1A/1B Without DSM/EE Measures
- Scenarios 1A/1B With Double DSM/EE Measures
- Scenarios 1A/1B With Committed Units Included
- Scenarios 1A/1B Without CO<sub>2</sub> Costs
- Scenarios 1A/1B With Higher Gas Prices
- Scenarios 1A/1B Without Chakachamna
- Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%
- Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced
- Scenarios 1A/1B With Susitna (Watana Option) Forced
- Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced
- Scenarios 1A/1B With Modular Nuclear
- Scenarios 1A/1B With Tidal
- Scenarios 1A/1B With Lower Coal Capital and Fuel Costs
- Scenarios 1A/1B With Federal Tax Credits for Renewables

### **1.7.3 Summary of Results – Economics and Emissions**

In this subsection, we provide a comparative summary of the economic and emissions results for all of the reference cases and sensitivity cases.

#### **1.7.3.1 Summary of Results - Economics**

Table 1-4 summarizes the economic results, including:

- Cumulative present value cost (from the utility perspective)
- Average wholesale power cost (from the utility perspective)
- Renewable energy in 2025
- Total capital investment

**Table 1-4**  
**Summary of Results – Economics**

Case	Cumulative Present Value Cost (\$000,000)	Average Wholesale Power Cost (¢ per kWh)	Renewable Energy in 2025 (%)	Total Capital Investment (\$000,000)
<b>Scenarios</b>				
Scenario 1A	\$13,625	17.26	62.32%	\$9,087
Scenario 1B	\$13,625	17.26	62.32%	\$9,087
Scenario 2A	\$20,162	19.75	42.64%	\$14,111
Scenario 2B	\$21,109	20.68	65.83%	\$18,805
<b>Sensitivities</b>				
1A/1B Without DSM/EE Measures	\$14,507	17.40	67.10%	\$8,603
1A/1B With Double DSM	\$12,546	15.89	65.15%	\$8,861
1A/1B With Committed Units Included	\$14,109	17.87	46.84%	\$8,090
1A/1B Without CO2 Costs	\$11,206	14.20	49.07%	\$8,381
1A/1B With Higher Gas Prices	\$14,064	17.82	61.95%	\$9,248
1A/1B Without Chakachamna	\$14,332	18.16	38.06%	\$7,719
1A/1B With Chakachamna Capital Costs Increased by 75%	\$14,332	18.16	38.06%	\$7,719
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	\$15,228	19.29	61.01%	\$12,421
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	\$15,040	19.05	63.01%	\$15,057
1A/1B With Susitna (Low Watana Expandable Option) Forced	\$15,346	19.44	63.01%	\$15,588
1A/1B With Susitna (Low Watana Expansion Option) Forced	\$14,854	18.82	66.90%	\$14,069
1A/1B With Susitna (Watana Option) Forced	\$15,683	19.87	70.97%	\$13,211
1A/1B With Susitna (High Devil Canyon Option) Forced	\$14,795	18.74	66.92%	\$11,633
1A/1B With Modular Nuclear	\$13,841	17.53	60.51%	\$9,105
1A/1B With Tidal	\$13,712	17.37	65.52%	\$9,679
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	\$13,625	17.26	62.32%	\$9,087
1A/1B With Tax Credits for Renewables	\$12,954	16.41	67.56%	\$9,256

**1.7.3.2 Summary of Results - Emissions**

Table 1-5 summarizes the emissions-related results of all of the reference and sensitivity cases. The following information is provided for each case:

- CO<sub>2</sub> emissions
- NO<sub>x</sub> emissions
- SO<sub>x</sub> emissions

**Table 1-5  
Summary of Results – Emissions**

Case	CO <sub>2</sub> (‘000 tons)	NO <sub>x</sub> (‘000 tons)	SO <sub>2</sub> (‘000 tons)
<b>Scenarios</b>			
Scenario 1A	80,259,047	124,215	21,768
Scenario 1B	80,259,047	124,215	21,768
Scenario 2A	152,318,066	133,642	24,476
Scenario 2B	125,498,202	140,897	26,348
<b>Sensitivities</b>			
1A/1B Without DSM/EE Measures	88,181,350	139,179	30,605
1A/1B With Double DSM	69,324,920	131,299	18,994
1A/1B With Committed Units Included	91,212,598	136,946	16,482
1A/1B Without CO2 Costs	100,753,030	134,031	23,960
1A/1B With Higher Gas Prices	78,323,066	121,700	25,232
1A/1B Without Chakachamna	105,643,650	133,577	25,700
1A/1B With Chakachamna Capital Costs Increased by 75%	105,643,650	133,577	25,700
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	82,328,762	127,921	22,124
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expansion Option) Forced	67,724,563	136,906	23,589
1A/1B With Susitna (Watana Option) Forced	70,966,059	111,307	19,171
1A/1B With Susitna (High Devil Canyon Option) Forced	71,853,368	121,538	19,909
1A/1B With Modular Nuclear	79,664,701	126,881	22,787
1A/1B With Tidal	75,598,948	121,306	21,067
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	80,259,047	124,215	21,768
1A/1B With Tax Credits for Renewables	74,046,352	129,384	18,832

**1.7.4 Results of Transmission Analysis**

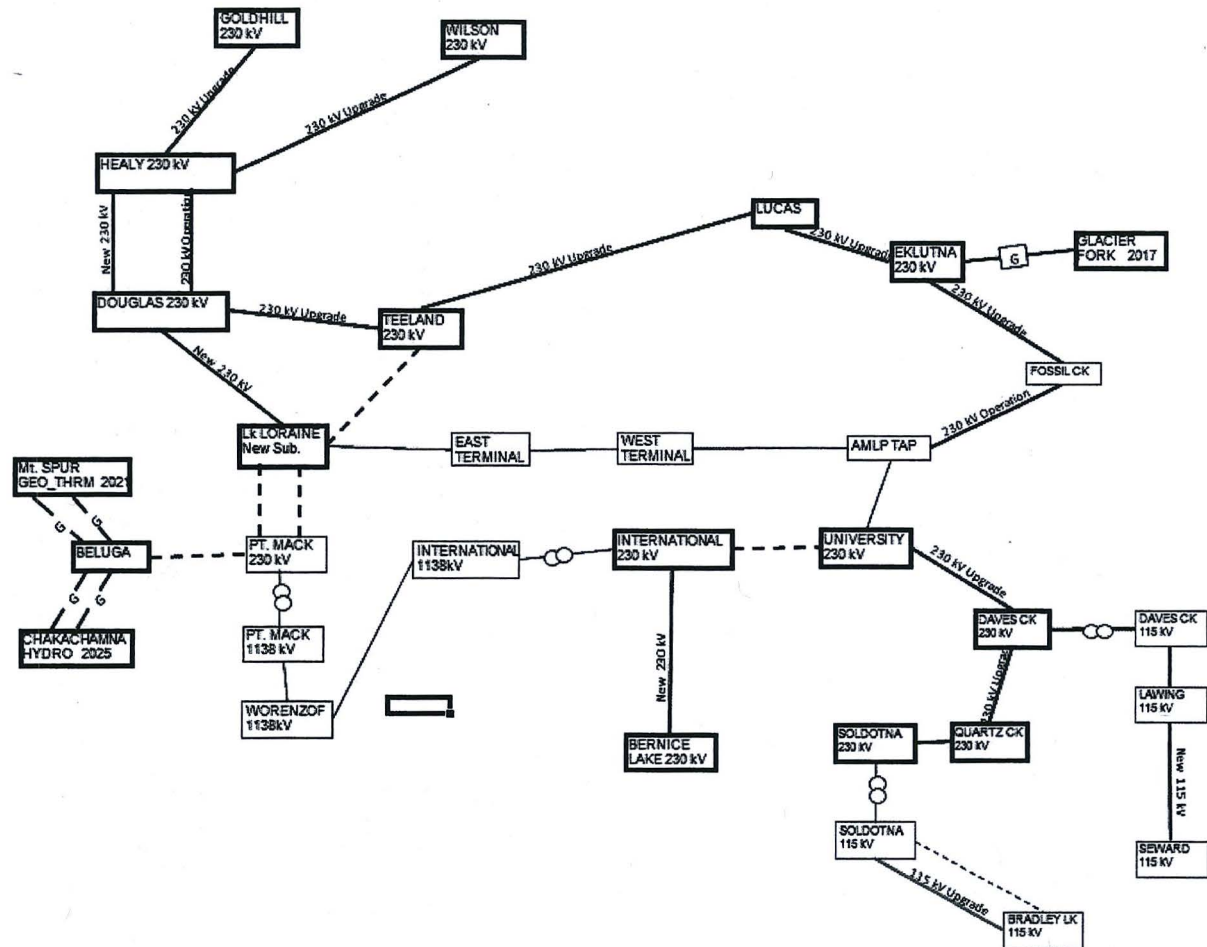
Table 1-6 lists the proposed transmission system expansions and enhancements that resulted from our transmission analysis. More detailed information on each of the identified transmission projects is provided in Section 12.

**Table 1-6  
Summary of Proposed Transmission Projects**

Project No.	Transmission Projects	Type	Cost (\$000)
A	Bernice Lake – International	New Build (230 kV)	227,500
B	Soldotna – Quartz Creek	R&R (230 kV)	126,500
C	Quartz Creek – University	R&R (230 kV)	165,000
D	Douglas – Teeland	R&R (230 kV)	62,500
E	Lake Lorraine – Douglas	New Build (230 kV)	80,000
F	Douglas – Healy	Upgrade (230 kV)	30,000
G	Douglas – Healy	New Build (230 kV)	252,000
H	Eklutna – Fossil Creek	Upgrade (230 kV)	65,000
I	Healy – Gold Hill	R&R (230 kV)	180,500
J	Healy – Wilson	Upgrade (230 kV)	32,000
K	Soldotna – Diamond Ridge	R&R (115 kV)	66,000
L	Lawing – Seward	Upgrade (115 kV)	15,450
M	Eklutna – Lucas	R&R(115 kV/230 kV)	12,300
N	Lucas – Teeland	R&R (230 kV)	51,100
O	Fossil Creek – Plant 2	Upgrade (230 kV)	13,650
P	Pt. Mackenzie – Plant 2	R&R (230 kV)	32,400
Q	Bernice Lake – Soldotna	Rebuild (115 kV)	24,000
R	Bernice Lake – Beaver Creek - Soldotna	Rebuild (115 kV)	24,000
S	Susitna Transmission Additions	New Build (230 kV)	57,000

A diagram that shows the location of the proposed transmission system enhancements is shown in Figure 1-7. This graphic shows the proposed transmission projects if the Susitna hydroelectric project is not developed. A similar graphic of proposed transmission projects if Susitna is built is provided in Section 12.

**Figure 1-7**  
**Location of Proposed Transmission Projects (Without Susitna)**



The following issues result from our transmission analysis:

- We were unable to complete a stability analysis based upon our proposed transmission system configuration prior to the completion of this project. This analysis is required to ensure that the proposed transmission system expansions and enhancements result in the necessary stability to ensure reliable electric service over the planning horizon. This analysis should be completed as part of the future work to further define, prioritize, and design specific transmission projects.

- In addition to the transmission lines listed above, other projects were considered that could contribute to improving the reliability of the Railbelt system. These projects generally fall into one or more of the following categories:
  - Providing reactive power (static var compensators – SVCs)
  - Providing or assisting with the provision of other ancillary services (regulation and/or spinning reserves)
  - Assistance in control of line flows or substation voltages
  - Assistance in the transition and coordination of transmission project implementation (mobile transforms or substations)
  - Communications and control facilities

Several of these projects have been identified and discussed while others will result from the transmission reliability assessment. Potential projects in this category include:

- Substation capacitor banks
  - Series capacitors
  - SVCs
  - Battery energy storage systems (BESS)
  - Mobile substations that could provide construction flexibility during the implementation phase
- Projects that could facilitate or complement the implementation of other projects (e.g., wind), were of particular interest during project discussions. These projects, if implemented, could smooth the transition and adoption by the utilities of the GRETC concept. One such project was the BESS that could provide much needed frequency regulation and potentially some spinning reserves when non-dispatchable projects, such as wind, are considered. A BESS was specified that could provide frequency regulation required by the system when wind projects were selected by the RIRP. The BESS was sized in relation to the size of the non-dispatchable project to be 50 percent of the project nominal capacity for a 20-minute duration. Although the performance of the BESS has not yet been analyzed as part of the stability analysis, the costs for each such system were included in the analysis. Other options (e.g., fly wheel storage technologies and compressed air energy storage) that could provide the required frequency regulation should also be considered.
  - It should be noted that if the need for frequency regulation is driven in part by an IPP-sponsored renewable project, policies will need to be adopted to allocate an appropriate portion of the regulation costs to those projects.
  - The Fire Island Wind Project is a 54 MW maximum output wind project. Each wind turbine will be equipped with reactive power and voltage support capabilities that should facilitate interconnection into the transmission grid. Current plans are to interconnect the project to the grid via a 34.5 kV underground and submarine cable to the Chugach 34.5 kV Raspberry Substation. There has been some discussions regarding the most appropriate transmission interconnection for the Fire Island Project and detailed interconnection studies have not been completed. The timeframe for implementing this project in order to qualify for available grants under the American Recovery and Reinvestment Act of 2009 (ARRA) could preclude more detailed transmission studies and consideration of alternatives to the currently proposed 34.5 kV interconnection. An option to consider if Fire Island is constructed is to lay cables from Fire Island to Anchorage insulated for 230 kV and review a transmission routing for the new transmission connection to the Kenai peninsula that would begin at the International 230 kV Substation to Bernice Lake Substation along the Kenai coast line then via submarine cable across the Cook Inlet to Fire Island. The interconnection would then use the 230 kV submarine cable previously laid over to the Anchorage coast then into the International 230 kV Substation.

- The recommended transmission system expansions and enhancements can not be justified based solely on economics. However, in addition to their underlying economics, these transmission projects are required to ensure the reliable delivery of electricity throughout the region over the 50-year planning horizon and to provide the foundation for future economic development efforts.

The proposed projects identified in **Section 12** are not presented in any specific order or priority. It was felt that the information currently available, as well as the uncertainty which exists surrounding the selected generation plans, did not permit a more definitive prioritization of projects. This does not mean, however, that all the projects in the list have the same impact on the reliability of the Railbelt system, or that the projects are equally important to each utility. In several instances the projects were in extremely poor physical condition and were scheduled to be repaired or rebuilt to prevent the lines from literally falling to the ground. To facilitate the immediate repairs to these lines, the projects that should be addressed within the next five years because of their potential impact on the reliability of the system have been identified. Additionally, some of the projects will need to be evaluated and specified further and funds have been identified to facilitate the studies that are required to further identify and schedule the transmission improvements that will be required.

The following projects and studies have been identified for priority attention (i.e., to be completed within the next five years) because of their immediate impact on the reliability of the existing system. All of the projects will require detailed system feasibility studies prior to actual implementation.

1. Soldotna to Quartz Creek Transmission Line (\$126.5 million – Project B)
2. Quartz Creek to University Transmission Line (\$165.0 million – Project C)
3. Douglas to Teeland Transmission Line (\$62.5 million – Project D)
4. Lake Lorraine to Douglas Transmission Line (\$80.0 million – Project E)
5. SVCs (\$25.0 million - Other Reliability Projects)
6. Funds to undertake the study of the Southern Intertie (\$1.0 million)
7. Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system (\$50.0 million, including cost of BESS – Other Reliability Projects)

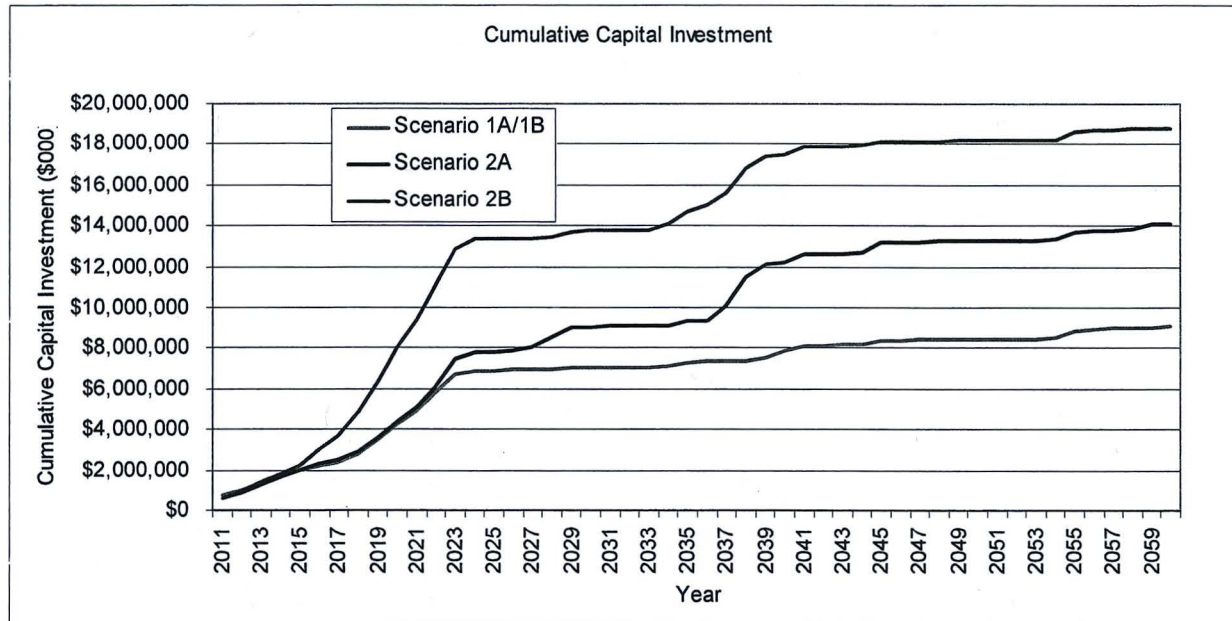
The total estimate costs necessary for transmission projects during the initial five years of the RIRP is \$510 million in 2009 dollars.

### **1.7.5 Results of Financial Analysis**

It will be difficult for the region to obtain the necessary financing for the DSM/EE, generation and transmission resources included in the alternative resource plans that were developed. The formation of a regional entity with some form of State assistance will help meet this challenge.

Figure 1-8 summarizes the cumulative capital investment required for each of the four base cases.

**Figure 1-8**  
**Required Cumulative Capital Investment for Each Base Case**



To assist in the completion of the financial analysis, AEA contracted with SNW to:

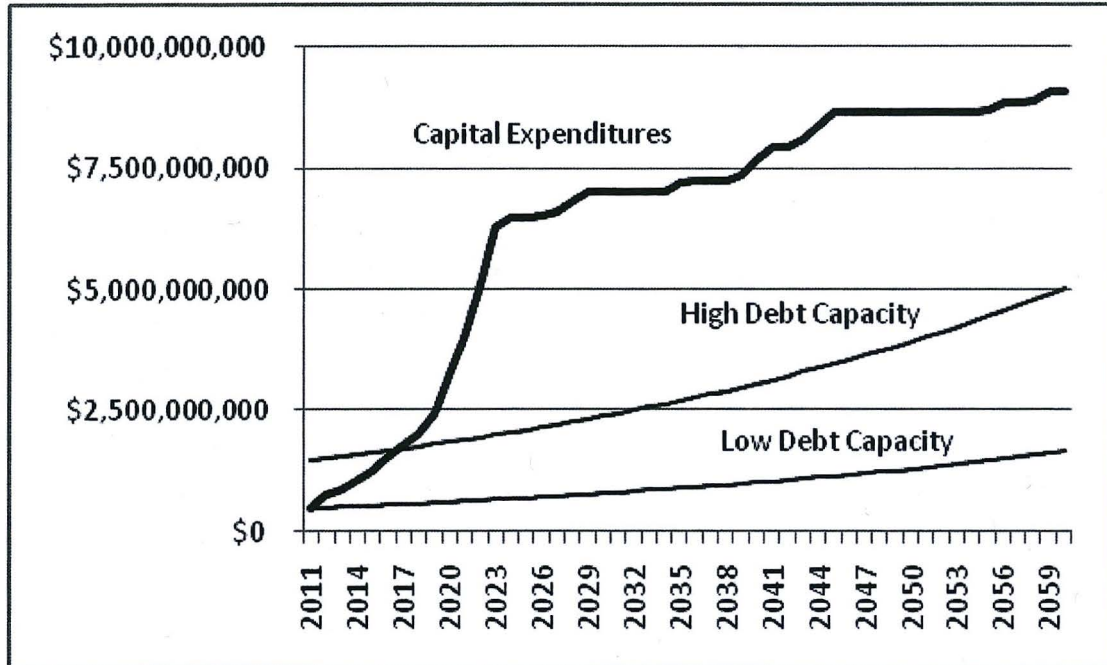
- Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities.
- Analyze strategies to capitalize selected RIRP assets by integrating State (which could include loans, State appropriations, Permanent Fund, State moral obligation bonds, etc.) and federal (e.g., USDA-RUS) financing resources with debt capital market resources.
- Develop a spreadsheet model that utilizes inputs from this RIRP analysis and overlays realistic debt capital funding to provide a total cost to ratepayers of the optimal resource plan.

The results of the financial analysis completed by SNW are provided in **Appendix B**.

Important conclusions from SNW's report include:

- The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or cooperative utility to independently secure debt financing without committing substantial amounts of equity of cash reserves.
- Figure 1-9 helps to put into context the scope of the required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent SNW's estimate of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

**Figure 1-9**  
**Required Cumulative Capital Investment (Scenarios 1A/1B) Relative to Railbelt Utility Debt Capacity**



Source: SNW Report included in Appendix C.

- A regional entity, such as GRETC, with “all outputs” contracts migrating over time to “all requirements” contracts will have greater access to capital than the combined capital capacity of the individual utilities.
- There are several strategies that could be employed to lower the RIRP-related capital costs to customers, including:
  - **Ratepayer Benefits Charge** – A charge levied on all ratepayers within the Railbelt system that would be used to cash fund and thereby defer borrowing for infrastructure capital.
  - **“Pay-Go” Versus Borrowing for Capital** – A pay-go financing structure minimizes the total cost of projects through the reduction in interest costs. A “pay-go” capital financing program is one in which ongoing capital projects are paid for from remaining revenue after operations and maintenance (O&M) expenses and debt service are paid for. A balance of these two funding approaches appears to be the most effective in lowering the overall cost of the RIRP, as well as spreading out the costs over a longer period of time.
  - **Construction Work in Progress (CWIP)** – CWIP is a rate methodology that allows for the recovery of interest expense on project construction expenditures through the base rate during construction, rather than capitalizing the interest until the projects are on-line and generating power. It should be noted that this rate methodology is sometimes criticized for shifting risks for shareholders to ratepayers; however, in the case of a public cooperative or municipal utility, the “shareholders” are the ratepayers.

- **State Financial Assistance** – State financial assistance could take a variety of forms as previously noted; for the purposes of this project, SNW focused on State assistance structured similarly to the Bradley Lake project. The benefits of State funding include: repayment flexibility, credit support/risk mitigation, and potential interest cost benefit.

**It should be noted that the economic comparison of resource options (using Strategist™ and PROMOD™) does not assume any of these financing strategies, including any State grants of Federal tax credits, with the exception of the Federal Tax Credits for Renewables Sensitivity Case.**

- The overall objective of SNW's analysis was to identify ways to overcome the funding challenges inherent with large-scale projects, including the length of construction time before the project is online and access to capital markets, and to develop strategies that could be used to produce equitable rates over the useful life of the assets being financed. With these challenges in mind, SNW developed separate versions of its model to capture the cost of financing under a "base case" scenario and an "alternative" scenario. The base case financing model was structured such that the list of RIRP projects during the first 20 years would be financed through the capital markets in advance of construction and that the cost of the financing in the form of debt service on the bonds would immediately be passed through to the ratepayers; the projects being financed over the balance of the 50-year period would be financed through cash flow created through normal rates and charges ("pay-go"), once debt service coverage from previous years has grown to levels that create cash flow balance amounts sufficient to pay for the projects as their construction costs come due. The alternative model was developed with the goal of minimizing the rate shock that may otherwise occur with such a large capital plan, and levelizing the rate over time so that the economic burden derived from these projects can be spread more equitably over the useful life of the projects being contemplated.
- In both the base and alternative cases, SNW transferred the excess operating cash flow that is generated to create the debt service coverage level, and using that balance to both partially fund the capital projects in the early years and almost fully fund the projects in the later years. In the alternative case, SNW also included: 1) a Capital Benefits Surcharge (\$0.01 per kWh) over the first 17 years, when approximately 75 percent of the capital projects will have been constructed, and 2) State assistance as an equity participant, structured in a manner similar to the Bradley Lake financing model (SNW assumed that the State would provide a \$2.4 billion zero-interest loan to GRETC to provide the upfront funding for the Chakachamna project, only to be paid back by GRETC out of system revenues over an extended period of time, and following the repayment of the potentially more expensive capital market debt).
- Under the base case, the maximum fixed charge rate on the capital portion alone is estimated to cost \$0.13 per kWh, while the average fixed charge rate over the 50-year period is \$0.07 per kWh.
- In the alternative case, the maximum fixed charge rate on the capital portion alone is estimated to cost \$0.08 per kWh, while the average fixed charge rate over the 50-year period is \$0.06 per kWh, not including the \$0.01 consumer benefit surcharge that is in place for the first 17 years.
- **While the average rates between the two cases are essentially the same, the maximum rate in the alternative case is much lower, showing the ability of innovative financing tools and ratemaking methodologies to overcome the funding challenges and provide equitable rates over the 50-year period.**

- The formation of a regional entity, such as GRETC, that would combine the existing resources and rate base of the Railbelt utilities, as well as provide an organized front in working to obtain private financing and the necessary levels of State assistance, would be, in SNW's opinion, a necessary next step towards achieving the goal of reliable energy for the Railbelt region now and in the future.

### 1.8 Implementation Risks and Issues

There are a number of general risks and issues that must be addressed regardless of the resource future that is chosen by stakeholders, including the utilities and State policy makers. Additionally, each alternative DSM/EE, generation and transmission resource type has its own specific risks and issues. **Section 14** includes a detailed discussion of these general and resource-specific implementation-related risks and issues.

#### A Note Regarding Risks

- Risk is an inherent element of any long-term integrated resource plan. This RIRP is not different.
- Risks associated with fuel supply, project development, operations, environmental, transmission, regulatory, and so forth, all affect the region's optimal future resource path. These risks are identified and discussed in this report.
- In many ways, this RIRP is the beginning of a journey; hard work is required to address these risks and make the difficult policy choices necessary to secure a reliable energy future.

#### 1.8.1 General Risks and Issues

General issues and risks related to the implementation of the RIRP include the following:

- **Organizational**, including:
  - The lack of a regional entity with the responsibility for implementing the RIRP will lead to suboptimal solutions, resulting in higher costs, lower reliability and the inability to manage the successful integration of DSM/EE and renewable resources into the Railbelt system.
  - To date, the Railbelt utilities have not been able to take full advantage of economies of scale for several reasons. Absent taking a regional approach to future resource planning and development, this reality will continue.
  - Fuel supply risks, including the future deliverability and price of natural gas.
  - Risks resulting from the inadequacy of the current regional transmission network.
  - Market development risks and issues, including the need to implement a competitive power procurement process to encourage the development of generation projects by IPPs, and the potential for large load increases.
  - Financing and rate issues, related to the ability of the region to finance the capital investments identified in the RIRP and the need to mitigate the rate impact of those investments.
  - Legislative and regulatory issues, including the potential impact that a State Energy Plan and the passage of energy-related policies could have on the RIRP.

### 1.8.2 Resource Specific Risks and Issues

Table 1-7 provides Black & Veatch's assessment of the relative magnitude of various categories of risks and issues for each resource type, including:

- **Resource Potential Risks** – the risk associated with the total energy and capacity that could be economically developed for each resource option.
- **Project Development and Operational Risks** – the risks and issues associated with the development of specific projects, including regulatory and permitting issues, the potential for construction costs overruns, actual operational performance relative to planned performance, and so forth. This category also includes non-completion risks once a project gets started, the risk that adverse operating conditions will severely damage the facilities resulting in a shorter useful life than expected, and project delay risks.
- **Fuel Supply Risks** – the risks and issues associated with the adequacy and pricing of required fuel supplies.
- **Environmental Risks** – the risks of environmental-related operational concerns and the potential for future changes in environmental regulations.
- **Transmission Constraint Risks** – the risk that the ability to move power from a specific generation resource to where that power is needed will be inadequate, an issue that is particularly important for large generation projects and remote renewable projects.
- **Financing Risks** – the risk that a regional entity or individual utility will not be able to obtain the financing required for specific resource options under reasonable and affordable terms and conditions.
- **Regulatory/Legislative Risks** – the risk that regulatory and legislative issues could affect the economic feasibility of specific resource options.
- **Price Stability Risks** – the risk that wholesale power costs will increase significantly as a result of changes in fuel prices and other factors (e.g., CO<sub>2</sub> costs).

### Fundamental RIRP-Related Risks and Uncertainties

#### **General**

- Regional implementation of RIRP elements
- Financial capability of Railbelt utilities

#### **DSM/Energy Efficiency (DSM/EE)**

- Lack of Alaska-specific information
- Total achievable resource potential
- Long-term reliability of savings
- Funding source

#### **Generation Resources – Conventional**

- Natural gas supplies, deliverability and prices
- Future emissions regulations (including CO<sub>2</sub>)

#### **Generation Resources – Renewables**

- Total economic resource potential
- Optimization of potential sites
- Project completion risks associated with large hydro and tidal
- Integration of non-dispatchable resources
- Environmental and permitting issues

#### **Transmission**

- Adequacy of backbone grid to move power and ensure reliability
- Generation site-specific interconnections
- Siting and permitting issues

**Table 1-7**  
**Resource Specific Risks and Issues - Summary**

Resource	Relative Magnitude of Risk/Issue							
	Resource Potential Risks	Project Development and Operational Risks	Fuel Supply Risks	Environmental Risks	Transmission Constraint Risks	Financing Risks	Regulatory/Legislative Risks	Price Stability Risks
DSM/EE	Moderate	Limited	N/A	N/A	N/A	Limited - Moderate	Moderate	Limited
<b>Generation Resources</b>								
Natural Gas	Limited	Limited	Significant	Moderate	Limited	Moderate	Moderate	Significant
Coal	Limited	Moderate-Significant	Limited	Moderate - Significant	Limited - Significant	Moderate - Significant	Moderate	Moderate
Modular Nuclear	Limited	Significant	Moderate	Significant	Limited	Significant	Significant	Significant
Large Hydro	Limited	Significant	Limited	Significant	Significant	Significant	Significant	Limited
Small Hydro	Moderate	Moderate	Limited	Moderate	Moderate	Limited - Moderate	Limited	Limited
Wind	Moderate	Moderate	N/A	Limited	Moderate	Limited - Moderate	Limited	Limited - Moderate
Geothermal	Moderate	Limited - Moderate	N/A	Limited - Moderate	Moderate - Significant	Limited - Moderate	Limited	Limited
Solid Waste	Limited	Moderate-Significant	N/A	Significant	Moderate	Limited - Moderate	Limited-Moderate	Moderate
Tidal	Limited	Significant	N/A	Significant	Moderate - Significant	Moderate - Significant	Moderate - Significant	Limited - Moderate
Transmission	Limited	Significant	N/A	Moderate	N/A	Significant	Moderate - Significant	N/A

## 1.9 Conclusions and Recommendations

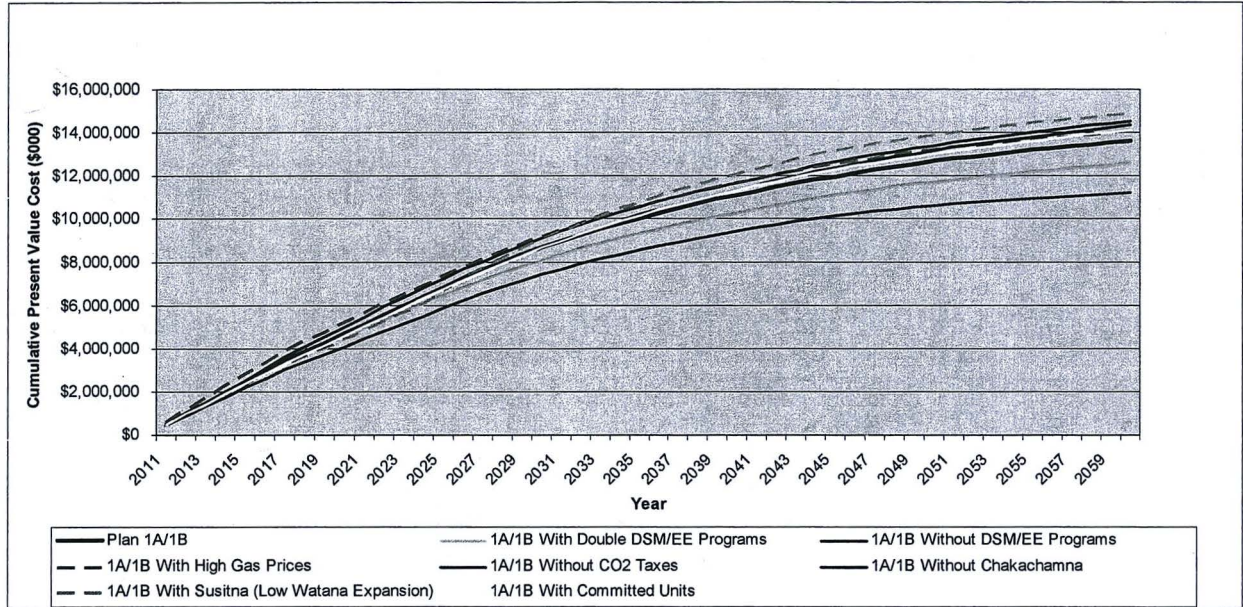
### 1.9.1 Conclusions

The primary conclusions from the RIRP study are discussed below.

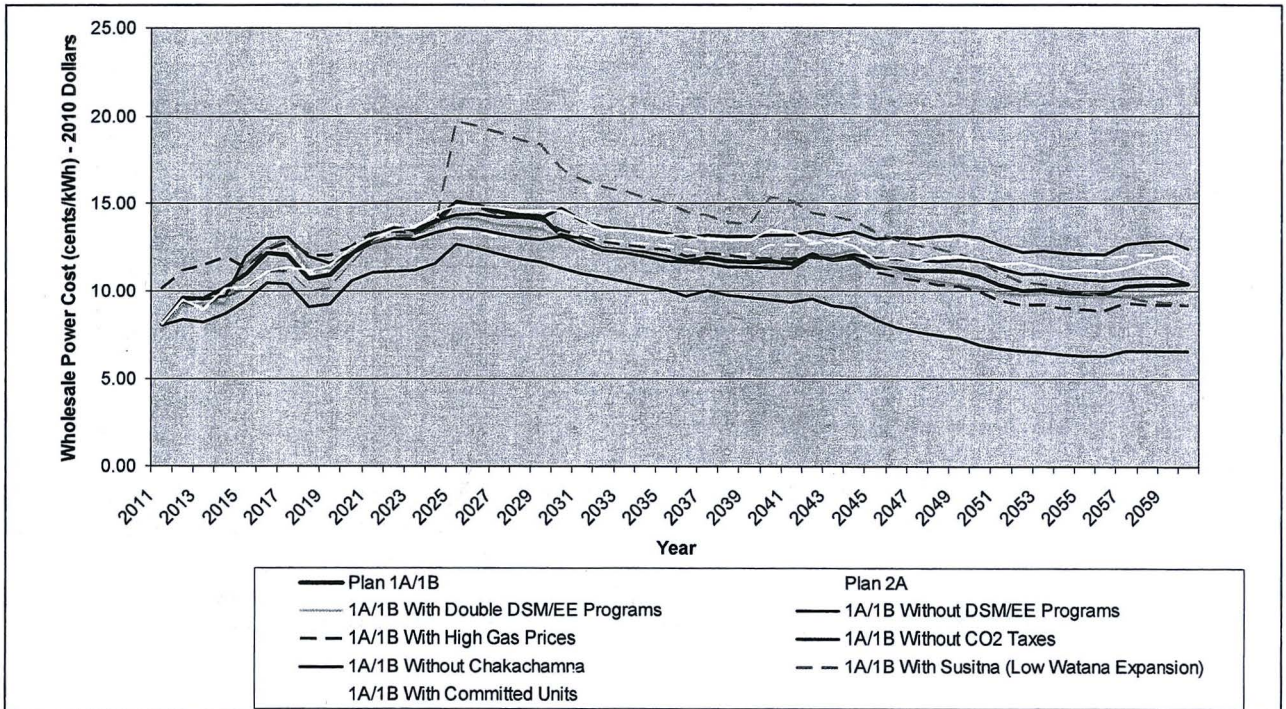
1. The current situation facing the Railbelt utilities includes a number of challenging issues that place the region at a historical crossroad regarding the mix of DSM/EE, generation, and transmission resources that it will rely on to economically and reliably meet the future electric needs of the region's citizens and businesses. As a result of these issues, the Railbelt utilities are faced with the following challenges:
  - A transmission network that is isolated and has limited total transfer capabilities and redundancies.
  - The inability of the region to take full advantage of economies of scale due to its limited size.
  - A heavy dependence on natural gas from the Cook Inlet for electric generation.
  - Limited and declining Cook Inlet gas deliverability.
  - Lack of natural gas storage capability.
  - The region's aging generation and transmission infrastructure.
  - A heavy reliance on older, inefficient natural gas generation assets.
  - The region's limited financing capability, both individually and collectively among the Railbelt utilities.
  - Duplicative and diffused generation and transmission expertise among the Railbelt utilities.
2. The key factors that drive the results of Black & Veatch's analysis include the following:
  - The risks and uncertainties that exist for all alternative DSM/EE, generation, and transmission resource options.
  - The future availability and price of natural gas.
  - The public acceptability and ability to permit a large hydroelectric project which is a greater concern, based upon Black & Veatch's discussions with numerous stakeholders, than the acceptability and ability to permit other types of renewable projects, such as wind and geothermal.
  - Potential future CO<sub>2</sub> prices, which would impact all fossil fuels, that may or may not result from proposed Federal legislation.
  - The region's existing transmission network, which limits: 1) the ability to transfer power between areas within the region to minimize power costs, and 2) places a maximum limit on the amount of non-dispatchable resources that can be integrated into the region's transmission grid.
  - The ability of the region to raise the required financing, either by the utilities on their own or through a regional G&T entity.
  - Whether the Railbelt utilities develop a number of currently proposed projects that were selected outside of a regional planning process.

Figures 1-10 and 1-11 graphically demonstrate how the results of the various reference and sensitivity cases are impacted by these important uncertainties. Figure 1-10 shows the cumulative present value cost for each year over the 50-year planning horizon; similarly, Figure 1-11 shows the annual wholesale power cost (cents/kWh) in 2010 dollars. In both cases, we have shown selected reference and sensitivity cases to highlight how dependent the results are to these key uncertainties.

**Figure 1-10**  
**Cumulative Present Value Cost – Selected Reference and Sensitivity Cases**



**Figure 1-11**  
**Annual Wholesale Power Cost – Selected Reference and Sensitivity Cases**



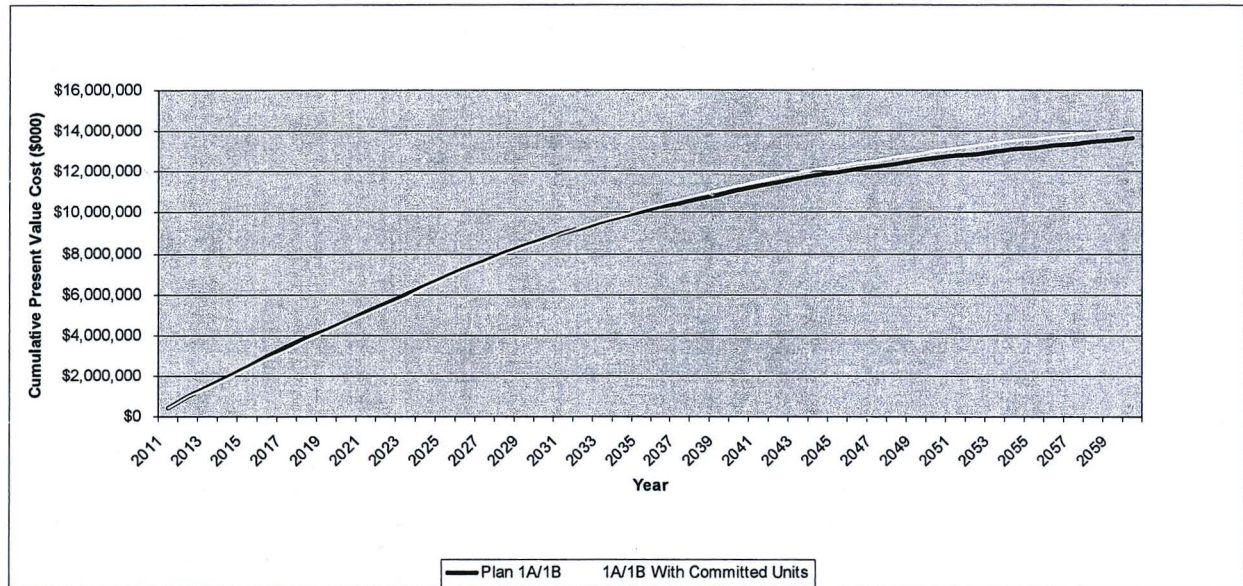
As can be seen in Figure 1-10, which shows cumulative net present value costs over the 50-year planning horizon, the 1A/1B With Susitna (Low Watana Expansion), 1A/1B With no DSM/EE Programs, 1A/1B Without Chakachamna, 1A/1B With Committed Units, and 1A/1B With High Gas Prices Sensitivity Cases are all higher cost than Scenario 1A/1B, in descending order. The 1A/1B With Double DSM/EE Programs and 1A/1B With No CO<sub>2</sub> Taxes Sensitivity Cases are lower cost than Scenario 1A/1B.

Figure 1-11 shows how significant the uncertainty regarding CO<sub>2</sub> taxes is with regard to the results. It also shows the economic value of achieving higher DSM/EE savings that were assumed in the Scenario 1A/1B Reference Case if those savings can be achieved. Also, shown is the fact that the other sensitivity cases are higher cost than Scenario 1A/1B.

3. The resource plans that were developed as part of this study for each Evaluation Scenario include a diverse portfolio of resources. If implemented, the RIRP will lead to:
  - The development of a resource mix resulting from a regional planning process.
  - Greater reliance on DSM/EE and renewable resources and a lower dependence on natural gas.
  - A more robust transmission network.
  - More effective spreading of risks among all areas of the region.
  - A greater ability to respond to large load growth should these load increases occur. Stated another way, the implementation of the RIRP will provide a stronger foundation upon which to base future economic development efforts.
4. The cost of this greater reliance on DSM/EE and renewable resources is less than the continued heavy reliance on natural gas based upon the base case gas price forecast that was used in this analysis. This result is achievable if the region builds a large hydroelectric project. There are uncertainties, at this point in time, regarding the environmental and/or geotechnical conditions under which a large hydroelectric project could be built. If a large hydroelectric facility can not be developed, or if the cost of the large hydroelectric project significantly exceeds the current preliminary estimates, then the costs associated with a predominately renewable future would be greater than continuing to rely on natural gas.
5. Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built.
6. Scenarios 2A and 2B were evaluated to determine what the impact would be if the demand in the region was significantly greater than it is today. In fact, the per unit power costs were not less than Scenario 1A/1B due to the cost of Susitna which was the resource chosen to meet this additional load.
7. Additionally, the implementation of a regional plan will result in lower costs than if the individual Railbelt utilities continue to go forward on their own. While the scope of this study did not include the development of separate integrated resource plans for each of the six Railbelt utilities, we did complete a sensitivity analysis to show the cost impact if the utilities develop their currently proposed projects (referred to as committed units) that were selected outside of a regional planning process. The Railbelt utilities are moving forward with these projects due to the existing uncertainty regarding the formation of GRETC. While this sensitivity case does not fully capture the incremental cost of the utilities acting independently over the 50-year planning horizon, it does provide an indication of the relative cost differential. Figure 1-12 shows the resulting total annual costs of the two different resource plans. In the aggregate, the cost of the Committed Unit Sensitivity Case was approximately

5.6 percent, or \$484 million on a cumulative net present value cost basis, higher than Scenario 1A/1B. The main conclusion to draw from this graphic is that there are significant cost savings associated with the Railbelt utilities implementing a plan that has been developed to minimize total regional costs, while ensuring reliable service, as opposed to the individual utilities working separately to meet the needs of their own customers.

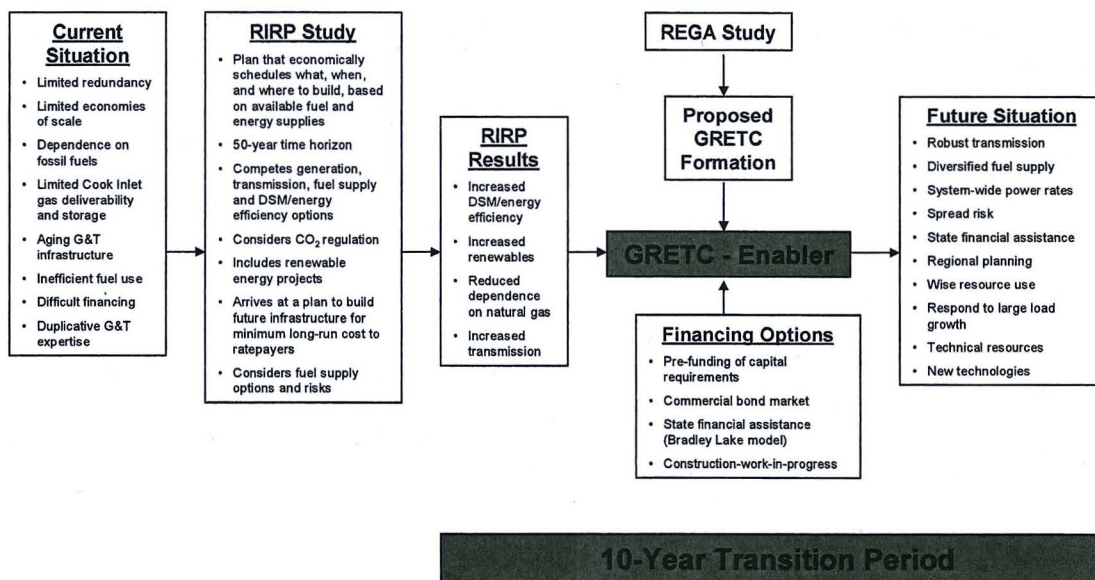
**Figure 1-12**  
**Comparison of Results - Scenario 1A/1B Versus Committed Units Sensitivity Case**



8. There are a number of risks and uncertainties regardless of the resource options chosen. For example: 1) there is a lack of Alaska-specific data upon which to build an aggressive region-wide DSM/EE program, 2) the future availability and price of natural gas affects the viability of natural gas generation, and 3) the total economic potential of various renewable resources is unknown at this time. In some cases, these risks and uncertainties (e.g., the ability to permit a large hydroelectric facility) might completely eliminate a particular resource option. Due to these risks and uncertainties, it will be important for the region to maintain flexibility so that changes to the preferred resource plan can be made, as necessary, as these resource-specific risks and uncertainties become more clear or get resolved.
9. Significant investments in the region's transmission network need to be made within the next 10 years to ensure the reliable and economic transfer of power throughout the region. Without these investments, providing economic and reliable electric service will be a greater challenge.
10. The increased reliance on non-dispatchable renewable resources (e.g., wind) will require a higher level of frequency regulation within the region to handle swings in electric output from these resources. An increased level of regulation has been included in Black & Veatch's transmission plan. Even with this increased regulation, however, the challenges associated with the integration of non-dispatchable resources will ultimately place a maximum limit on the amount of these resources that can be developed.

11. The implementation of the RIRP does not require that a regional generation and transmission entity (e.g., GRETC) be formed. However, the absence of a regional entity with the responsibility for implementing the RIRP will increase the difficulty of the region's ability to implement a regional plan and, in fact, Black & Veatch believes that the lack of a regional entity will, as a practical matter, mean that the RIRP will not be fully implemented. As a consequence, the favorable outcomes of the RIRP discussed above would not be realized. The interplay between the formation of a regional entity and the RIRP is shown in Figure 1-13.

**Figure 1-13**  
**Interplay Between GRETC and Regional Integrated Resource Plan**



### 1.9.2 Recommendations

This subsection summarizes the overall recommendations arising from this study, broken down into the following three categories:

- Recommendations – General
- Recommendations – Capital Projects
- Recommendations – Other

#### 1.9.2.1 Recommendations - General

The following general actions should be taken to ensure the timely implementation of the RIRP:

1. The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity.

2. The State should establish certain energy-related policies, including:
  - The pursuit of large hydroelectric facilities
  - DSM/EE program targets
  - RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal (which will become commercially mature during the 50-year planning horizon) projects in addition to large hydroelectric projects; the passage of an RPS would be meaningful as a policy statement even though the preferred resource plan would achieve a 50 percent renewable level by 2025.
  - System benefit charge to fund DSM/EE programs and or renewable projects
3. The State should work closely with the Railbelt utilities and other stakeholders to establish the specific preferred resource plan. In establishing the preferred resource plan, the economic results of the various reference cases and sensitivity cases evaluated in this study should be considered, as well as the environmental impacts discussed in Section 13 and the project-specific risks discussed in Section 14.
4. Black & Veatch believes that the Scenario 1A/1B resource plan should be the starting point for the selection of the preferred resource plan as discussed below. Table 1-8 provides a summary of the specific resources that were selected, based upon economics, in the Scenario 1A/1B resource plan during the first 10 years.

A project selected in Scenario 1A/1B after the first 10 years especially worthy of mention is the Chakachamna Hydroelectric Project in 2025.

Another important consideration in the selection of a preferred resource plan is evaluation of the sensitivity cases evaluated, as presented in Section 13. Issues addressed through the sensitivity cases and considered in Black & Veatch's selection of a preferred resource plan include the following and are discussed in Table 1-9. Following that discussion,

- What if CO<sub>2</sub> regulation doesn't occur?
- What is the effect if the committed units are installed?
- What if Chakachamna doesn't get developed?
- What would be the impact of the alternative Susitna projects?

There are several projects that are significantly under development and included in the preferred resource plan. These significantly developed projects include:

- Healy Clean Coal Project (HCCP)
- Southcentral Power Project
- Fire Island Wind Project
- Nikiski Wind Project

These projects are discussed in Table 1-10.

In addition to these resources, Black & Veatch believes that Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of the projects could actually be built.

**Table 1-8  
Resources Selected in Scenario 1A/1B Resource Plan**

Project	Discussion
DSM/EE Resources	The full level of DSM/EE resources evaluated was selected based upon their relative economics. Sensitivity analysis indicates that even greater levels of DSM/EE may be cost-effective. The lack of Alaska-specific DSM/EE data causes the exact level of cost-effective DSM/EE to remain uncertain.
Nikiski Wind	The RIRP selected this project in the initial year. It is being developed as an IPP project and is well along in the development process. The ARRA potentially offers significant financial incentives if this project is completed by January 1, 2013. These incentives could further improve its competitiveness. As a wind unit, it has no impact on planning reserves, but contributes to renewable generation.
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. This project was selected in the initial year of the plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the \$25 million grant from the State for interconnection. This project was selected in 2012.
Anchorage 1x1 6FA Combined Cycle	The RIRP selected this unit for commercial operation in 2013. This unit is very similar in size and performance to the Southcentral Power Project being developed as a joint ownership project by Chugach and ML&P for 2013 commercial operation. The project appears well under development with the combustion turbines already under contract. The project fits well with the RIRP and the joint ownership at least partially reflects the GRETC joint development concept.
Glacier Fork Hydroelectric Project	The RIRP selected this project for commercial operation in 2014, the first year that it was available for commercial operation in the models. Of the large hydroelectric projects, Glacier Fork is by far the least developed. Glacier Fork has very limited storage and thus does not offer the system operating flexibility of the other large hydroelectric units. There is also significant uncertainty with respect to its capital cost and ability to be licensed. Because it has such a minimal level of firm generation in the winter, it does not contribute significantly to planning reserves, but does contribute about 6 percent of the renewable energy to the Railbelt. Detailed feasibility studies and licensing are required to advance this option.
Anchorage and GVEA MSW Units	The RIRP selected these units in 2015 and 2017. Historically, mass burn MSW units such as those modeled, have faced significant opposition due to emissions of mercury, dioxin, and other pollutants. Other technologies which result in lower emissions, such as plasma arc, are not commercially demonstrated. The units included in the RIRP are relatively small (26 MW in total) and are not required to be installed to meet planning reserve requirements, but their base load nature contributes nearly 4 percent of the renewable energy. Detailed feasibility studies would be required to advance this alternative.
GVEA North Pole Retrofit	The retrofitting of GVEA's North Pole combined cycle unit with a second train using a LM6000 combustion turbine and heat recovery steam generator was selected in 2018 coincident with the assumption of the availability of natural gas to GVEA. The retrofit takes advantage of capital and operating cost savings resulting from the existing installation.

**Table 1-8 (Continued)**  
**Resources Selected in Scenario 1A/1B Resource Plan**

Project	Discussion
Mt. Spurr Geothermal Project	The first unit at Mt. Spurr was selected in 2020. Mt. Spurr's developer, Ormat, currently has commercial operation scheduled for 2017. Significant development activity remains for the project including verifying the geothermal resource. Mt. Spurr will also require significant infrastructure development including access roads and transmission lines. This infrastructure may correspond to similar infrastructure development required for Chakachamna which is selected in 2025 in the RIRP. As the implementation of the RIRP unfolds, there will likely be the need to adjust the timing of the resource additions following the implementation of the initial projects.

**Table 1-9**  
**Impact of Selected Issues on the Preferred Resource Plan**

Issue	Discussion
CO <sub>2</sub> Regulation	The sensitivity case for Scenario 1A without CO <sub>2</sub> regulation selects the Anchorage LMS 100 project instead of Fire Island and Mt. Spurr in the first 10 years.
Committed Units	Installation of the committed units significantly increases the cost of Scenario 1A/1B. In addition to the committed units, this plan selects five wind units from 2016 through 2024 in response to CO <sub>2</sub> regulation. The plan with the committed units eliminates Chakachamna and does not meet the 50 percent renewable target by 2025.
Chakachamna	Chakachamna could fail to develop because of licensing or technical issues. Also, if the cost of Chakachamna were to increase to be equivalent to the alternative Susitna projects on a GWh basis, it would not be selected. The sensitivity case without Chakachamna for the first 10 years is identical to Scenario 1A/1B. The case does not meet the 50 percent renewable target by 2025 and is 5.2 percent higher in cost than the preferred resource plan.
Susitna	None of the alternative Susitna projects are selected in the Scenario 1A/1B resource plan. The least cost Susitna option, which is Low Watana Expansion, is 15.3 percent more than the preferred resource plan and 9.0 percent more than the case without Chakachamna. The 50 percent renewable requirement can not be met without Susitna if Chakachamna is not available.

**Table 1-10  
Projects Significantly Under Development**

Project	Discussion	Preferred Resource Plan Recommendation
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. The project is part of the least cost scenario. While CO <sub>2</sub> regulation has been assumed in the RIRP, those regulations are not in place and there is no absolute assurance that they will be in place or what the costs from the regulations will be. HCCP adds further fuel diversity to the Railbelt, especially to GVEA who doesn't currently have access to natural gas. As a steam unit, HCCP improves transmission system stability.	Black & Veatch recommends that HCCP be included in the preferred resource plan.
Southcentral Power Project	The Southcentral Power Project is well under development with the combustion turbines purchased. The timing and technology are generally consistent with the preferred resource plan. The project will improve the efficiency of natural gas generation in the Railbelt and permit the retirement of aging units.	Black & Veatch recommends the continued development of the Southcentral Power Project as part of the preferred resource plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the \$25 million grant from the State for interconnection. This project is part of the least cost plan and provides renewable energy to the Railbelt system. Issues with interconnection and regulation will need to be resolved.	Subject to the successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.
Nikiski Wind Project	The Nikiski Wind Project is an IPP project like Fire Island and has the same potential to benefit from ARRA. It is also part of the least cost plan.	Like Fire Island, subject to successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.

In the case of the Mt. Spurr Geothermal Project, exploration should continue to determine the extent and characteristics of the geothermal resource at the site.

In the case of Susitna, the primary focus should be on completing engineering studies to optimize the size and minimize the costs of the project. In the case of Glacier Fork and Chakachamna, the additional work should look for “fatal flaws”.

Additionally, further analysis needs to be completed relative to integrating wind and other non-dispatchable renewable resources into the transmission network.

5. The State and Railbelt utilities should develop a public outreach program to inform the general public regarding the preferred resource plan, including the costs and benefits.
6. The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan.
7. The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues. Specific actions that should be taken include:
  - Development of local gas storage capabilities with open access among all market participants as soon as possible.
  - Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured either in the Cook Inlet, from the North Slope or from long-term LNG supplies.
  - The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options. Once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources.
  - Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins. This action is required to provide the necessary long-term contractual certainty to result in additional exploration and development.

#### **1.9.2.2 Recommendations – Capital Projects**

Efforts should be undertaken to begin the development, including detailed engineering and permitting activities, of the following capital projects, which are included in Black & Veatch’s recommended preferred resource plan.

1. Develop a comprehensive region-wide portfolio of DSM/EE programs.
2. Generation projects:
  - Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project)
  - Glacier Fork Hydroelectric Project
  - Generic Anchorage MSW Project
  - Generic GVEA MSW Project
  - GVEA North Pole Retrofit Project
  - Mt. Spurr Geothermal Project
  - Chakachamna Hydroelectric Project
  - Susitna Hydroelectric Project

3. Transmission and related substation projects, including the following projects which have been identified for priority attention because of their immediate impact on the reliability of the existing system. These projects are estimated to be required within the next five years.
  - Soldotna to Quartz Creek Transmission Line (\$84 million – Project B)
  - Quartz Creek to University Transmission Line (\$112.5 million – Project C)
  - Douglas to Teeland Transmission Line (\$37.5 million – Project D)
  - Lake Lorraine to Douglas Transmission Line (\$80 million – Project E)
  - SVCs (\$25 million - Other Reliability Projects)
  - Funds to undertake the study of the Southern Intertie (\$1 million)
  - Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system (\$50 million, including cost of BESS – Other Reliability Projects)

### 1.9.2.3 Recommendations - Other

Other actions, related to the implementation of the RIRP, that should be undertaken include:

1. The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts.
2. Develop a regional DSM/EE program measurement and evaluation protocol.
3. If GRETC is not formed, some type of a regional entity should be formed to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities.
4. Likewise, if GRETC is not formed, some type of a regional entity should be formed to develop the renewable resources included in the preferred resource plan.
5. Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs.
6. Aggressively pursue available Federal funding for DSM/EE programs and renewable projects.
7. Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to be economic within the planning horizon.
8. The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects, and conduct the necessary studies to address these issues and requirements.
9. Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable resources included in the preferred resource plan.
10. Develop streamlined siting and permitting processes for transmission projects.
11. Develop a regional frequency regulation strategy for non-dispatchable resources.
12. Develop a regional competitive power procurement process and a standard power purchase agreement to provide IPPs an equal opportunity to submit qualified proposals to develop specific projects.

13. Federal legislative and regulatory activities, including those related to emissions regulations, should be monitored closely and influenced to the degree possible.
14. Monitor the licensing progress of small modular nuclear units.

**1.10 Near-Term Implementation Action Plan (2010-2012)**

The purpose of this subsection section is to identify our overall recommendations regarding the near-term implementation plan, covering the period from 2010 to 2012. Our recommended actions are grouped into the following categories:

- General actions
- Capital projects
- Supporting studies and activities
- Other actions

In many ways, this near-term implementation plan shown in Tables 1-11 through 1-14 serves two objectives. First, it identifies that steps that should be taken during the next three years regardless of the alternative resource plan that is chosen as the preferred resource plan. Second, it is intended to maintain flexibility as the uncertainties and risks associated with each alternative resource plan become more clear and or resolved.

## 1.10.1 General Actions

**Table 1-11**  
**Near-Term Implementation Action Plan – General Actions**

Actions			
Category	Description	Timeline	Est. Cost
General Actions	<ul style="list-style-type: none"> <li>The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity</li> </ul>	2010	\$6.8 million
	<ul style="list-style-type: none"> <li>Establish State energy-related policies regarding:               <ul style="list-style-type: none"> <li>The pursuit of large hydroelectric facilities</li> <li>DSM/EE program targets</li> <li>RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal projects</li> <li>System benefit charge to fund DSM/EE programs and or renewable projects</li> </ul> </li> </ul>	2010-2011	\$0.2 million
	<ul style="list-style-type: none"> <li>The State should work closely with the Railbelt utilities and other stakeholders to establish the preferred resource plan, using the Scenario 1A/1B resource plan as the starting point</li> </ul>	2010	Not applicable
	<ul style="list-style-type: none"> <li>Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of these projects could actually be built</li> </ul>	2010-2011	To be determined
	<ul style="list-style-type: none"> <li>Develop a public outreach program to inform the public regarding the preferred resource plan, including the costs and benefits</li> </ul>	2010-2011	\$0.1 million
	<ul style="list-style-type: none"> <li>The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&amp;T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan</li> </ul>	2010-2011	Not applicable

**Table 1-11 (Continued)**  
**Near-Term Implementation Action Plan – General Actions**

Actions			
Category	Description	Timeline	Est. Cost
	<ul style="list-style-type: none"> <li>• The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues; specific actions that should be taken include:               <ul style="list-style-type: none"> <li>○ Development of local gas storage capabilities as soon as possible</li> <li>○ Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured</li> <li>○ The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options; once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources</li> <li>○ Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins</li> </ul> </li> </ul>	2010-2012	To be determined

## 1.10.2 Capital Projects

**Table 1-12**  
**Near-Term Implementation Action Plan – Capital Projects**

Actions			
Category	Description	Timeline	Est. Cost
Capital Projects	<ul style="list-style-type: none"> <li>• Develop a comprehensive region-wide portfolio of DSM/EE programs within first six years</li> </ul>	2011-2016	\$34 million
	<ul style="list-style-type: none"> <li>• Begin detailed engineering and permitting activities associated with the generation projects identified in the initial years of the preferred resource plan, including:               <ul style="list-style-type: none"> <li>○ Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project)</li> <li>○ Glacier Fork Hydroelectric Project</li> <li>○ Generic Anchorage MSW Project</li> <li>○ Generic GVEA MSW Project</li> <li>○ GVEA North Pole Retrofit Project</li> <li>○ Mt. Spurr Geothermal Project</li> <li>○ Chakachamna Hydroelectric Project</li> <li>○ Susitna Hydroelectric Project</li> </ul> </li> </ul>	2011-2016	Varies by project
	<ul style="list-style-type: none"> <li>• Begin detailed engineering and permitting activities associated with the transmission projects identified in the initial years of the preferred resource plan, including:               <ul style="list-style-type: none"> <li>○ Soldotna to Quartz Creek Transmission Line</li> <li>○ Quartz Creek to University Transmission Line</li> <li>○ Douglas to Teeland Transmission Line</li> <li>○ Lake Lorraine to Douglas Transmission Line</li> <li>○ SVCs</li> <li>○ Funds to undertake the study of the Southern Intertie</li> <li>○ Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system</li> </ul> </li> </ul>	2011-2016	Varies by project

## 1.10.3 Supporting Studies and Activities

**Table 1-13**  
**Near-Term Implementation Action Plan – Supporting Studies and Activities**

Actions			
Category	Description	Timeline	Est. Cost
Supporting Studies and Activities	<ul style="list-style-type: none"> <li>The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts</li> </ul>	2010-2011	\$1.0 million
	<ul style="list-style-type: none"> <li>Develop a regional DSM/EE program measurement and evaluation protocol</li> </ul>	2012	\$0.1 million
	<ul style="list-style-type: none"> <li>The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects</li> </ul>	2010-2011	\$0.2 million
	<ul style="list-style-type: none"> <li>Conduct necessary studies to address resource agencies' issues and data requirements related to large hydroelectric and tidal projects</li> </ul>	2011-2012	To be determined
	<ul style="list-style-type: none"> <li>Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable projects included in the preferred resource plan</li> </ul>	2010-2012	\$1.5 million
	<ul style="list-style-type: none"> <li>Develop a regional frequency regulation strategy for non-dispatchable resources</li> </ul>	2011	\$0.5 million
	<ul style="list-style-type: none"> <li>Develop a regional standard power purchase agreement for IPP-developed projects</li> </ul>	2011-2012	\$0.2 million
	<ul style="list-style-type: none"> <li>Develop a regional competitive power procurement process to encourage IPP development of projects included in the preferred resource plan</li> </ul>	2011-2012	\$0.2 million

## 1.10.4 Other Actions

**Table 1-14**  
**Near-Term Implementation Action Plan – Other Actions**

Actions			
Category	Description	Timeline	Est. Cost
Other Actions	<ul style="list-style-type: none"> <li>Form a regional entity (if GRETC is not formed) to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities</li> </ul>	2010-2011	Subject to decision regarding formation of GRETC
	<ul style="list-style-type: none"> <li>Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs</li> </ul>	2010-2011	\$0.2 million
	<ul style="list-style-type: none"> <li>Aggressively pursue available Federal funding for DSM/EE programs</li> </ul>	2010-2011	\$0.2 million
	<ul style="list-style-type: none"> <li>Form a regional entity (if GRETC is not formed) and encourage IPPs to identify and develop renewable projects that are included in the preferred resource plan</li> </ul>	2011-2012	Subject to decision regarding formation of GRETC
	<ul style="list-style-type: none"> <li>Further encourage the development of tidal power</li> </ul>	Ongoing	To be determined
	<ul style="list-style-type: none"> <li>Monitor, and influence to the degree possible, Federal legislative and regulatory activities, including those related to emissions regulations</li> </ul>	Ongoing	Not applicable
	<ul style="list-style-type: none"> <li>Aggressively pursue available Federal funding for renewable projects</li> </ul>	2010-2012	\$0.2 million
	<ul style="list-style-type: none"> <li>Develop streamlined siting and permitting processes for transmission projects</li> </ul>	2010-2011	\$0.5 million
	<ul style="list-style-type: none"> <li>Monitor the licensing progress of small modular nuclear units</li> </ul>	Ongoing	Not applicable

# Alaska Environmental Power



April 4, 2018  
Rep. Adam Wool, Chair  
House Energy Committee Members  
State of Alaska Legislature  
House Special Committee on Energy

RE: Alaska Environmental Power support for HB 382

Dear Chairman Wool and Energy Committee Members,

Alaska Environmental Power operates the Delta Wind Farm and sells 2 Megawatts (MW) of renewable energy generation to Golden Valley Electrical Association (GVEA) under their limited agreement. I am the CEO/President of Alaska Environmental Power LLC, that owns and operates the Delta Wind Farm. I have personally invested and been involved in Renewable Energy development in Alaska for more than ten years. I have a great deal of knowledge and experience in working with utilities and Alaska's utility and interconnection statutes and regulations. My company led the effort and was successful in the R-13-002 docket in ushering in Alaska's version of Utility Regulatory Policies Act (PURPA) compliance that had been on the books since 1982.

Our wind farm is limited, by GVEA, to 2 Megawatts of energy production and for years we have tried to increase capacity and continue to expand our energy production to 24 MW to serve interior Alaska. This win-win energy situation is a private capital investment providing public benefits and creating private sector construction jobs for Alaska that currently has the highest unemployment in the US.

My company supports HB 382. Over the course of my energy development experience I have participated in many hearings and public sessions about how Alaska could better serve our Railbelt Grid through lowering costs and increasing efficiencies, integrating renewable energy and providing more resilient and diversified energy resources for Alaskans. I have seen and have the economic scars which proves the Alaska utility has self-build bias and parochial utility turf issues which provide a disservice to Railbelt Grid utility ratepayers.

I support the Independent Service Operator (ISO) concept presented in HB 382 because it requires *by statute* an open access, non-discriminatory transmission that is overseen by an independent board comprised of a broad cross section of well-informed, non-partisan independent Alaskans open to best practices. This independence requirement is essential to ensure that the Railbelt Grid as a public asset is managed in the public interest. As you know, the Railbelt Grid transmission assets were mostly paid for by state and federal funding. Upgrading the Railbelt Grid system has fallen behind our needs and lessened the energy security that Alaskan Railbelt Grid consumers require. An ISO overseeing the Railbelt Grid assets for the benefit of the public ensuring open access and nondiscriminatory tariffs and

access will help attract private capital, increase competition and help assure that economically viable energy projects can develop and sell on the Railbelt Grid market.

It is painfully clear to Fairbanks consumer's that something is out of balance as we pay the highest cost on the Railbelt Grid for power under the current constraints and control of Railbelt Grid that cannot agree amongst themselves, let alone work with renewable energy producers to improve energy security and reliability for a prosperous Alaskan economy. HB 382 can't cover everything but is a step in the right direction by putting a public dominated independent board ISO in control of the Railbelt Grid.

Rep. Wool should be commended for sponsoring this legislation and I ask like-minded members of the Energy Committee to co-sponsor this legislation as history tells us nothing will occur in fixing the Railbelt Grid without Legislative direction. Our economy and the public are no longer willing to listen to "stall by studies" and observe utility infighting while our public is not served. We deserve better and HB 382 helps Alaskan Railbelt Grid consumers by putting the public first.

I appreciate and thank you for your consideration of my comments on this important bill.

Sincerely,

A handwritten signature in blue ink, appearing to read "Mike Craft", with a long horizontal line extending to the right.

Mike Craft

CEO/President