10.0 SUPPLY-SIDE OPTIONS

The purpose of this section is to summarize the input assumptions that Black & Veatch used related to the various supply-side resource options considered in the RIRP study. Information is provided for both conventional technologies and renewable resources.

10.1 Conventional Technologies

10.1.1 Introduction

This subsection describes and characterizes various conventional supply-side technologies including General Electric (GE) LM6000 and LMS100 simple cycle units, GE 6FA combined cycle units and a 130 MW pulverized coal (PC) facility. In addition to greenfield developments, the option of repowering Beluga Unit 8 has been considered.

10.1.2 Capital, and Operating and Maintenance (O&M) Cost Assumptions

The capital cost estimates developed in this report include both direct and indirect costs. An allowance for general owner's cost items (exclusive of escalation, financing fees, and interest during construction), as summarized in Table 10-1, has been accounted for in the cost estimates or provided as a percentage of total costs. The capital cost estimates were developed on an engineer, procure, and construct (EPC) basis.

The O&M cost estimates were derived from proprietary Black & Veatch O&M estimating tools and representative estimates for similar projects. Costs are based on vendor estimates and recommendations, and estimated performance information. The cost estimates are divided into fixed and variable O&M. Fixed O&M costs, expressed as dollars per unit of capacity per year ($/kW-yr), do not vary directly with plant power generation and consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance and other fees. Variable O&M costs, expressed as dollars per unit of generation ($/MWh) tend to vary in near direct proportion to the output of the unit. Variable O&M include costs associated with equipment outage maintenance, utilities, chemicals, and other consumables. Fuel costs are determined separately and are not included in either fixed or variable O&M costs.

10.1.3 Generating Alternatives Assumptions

10.1.3.1 General Capital Cost Assumptions

Unless otherwise discussed, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- The plant will not be located on wetlands nor require any other mitigation.
- Service and fire water will be supplied via on-site groundwater wells.
- Potable water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Costs for transmission lines and switching stations are included as part of the owner's cost.

Table 10-1
Possible Owner's Costs

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (e.g., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Start-up/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate, but not in direct capital cost)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

10.1.3.2 Combustion Turbine Capital Cost Assumptions

- Combustion turbines will be fueled with natural gas as the primary fuel with an option provided for dual fuel with No. 2 ultra-low sulfur diesel (ULSD) fuel oil as the backup fuel. The cost of fuel unloading and delivery to the site(s) is included.
- The LM6000 and the LMS100 will utilize water injection for primary NO_x control when operating on fuel oil. The 6FA configurations will utilize dry low NO_x burners when operating on natural gas and water injection when operating on fuel oil.
- All of the combustion turbine configurations will include selective catalytic reduction (SCR) and a CO catalyst.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the LM6000 and the combined cycle alternatives. Gas compressors will be included for the LMS100 combustion turbine. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be provided via portable demineralizers for simple cycle alternatives and will be supplied by a demineralized water treatment system for the combined cycle options.
- Both of the combustion turbine combined cycle configurations will utilize air cooled condensers for heat rejection.
- None of the combustion turbine configurations will utilize inlet cooling.
- Field erected storage tanks include the following:
  - Service/fire water storage tank.
  - Fuel oil storage tank (3 days storage capacity).
  - Demineralized water storage tank (3 days storage capacity).

10.1.3.3 Coal Facility Capital Cost Assumptions

- The PC plant will be equipped with an SCR for NO_x control, an activated carbon injection system for mercury reduction, a dry flue gas desulfurization unit for sulfur reduction and a fabric filter system for managing particulate emissions.
- The subcritical PC plant will utilize an air cooled condenser for heat rejection.

10.1.3.4 Direct Cost Assumptions

- Total direct capital costs are expressed in 2009 dollars.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for start-up are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

10.1.3.5 Indirect Cost Assumptions

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.

- Technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Start-up and commissioning spare parts.
- Allowance for funds used during construction and financing fees will be accounted for separately as part of the economic evaluations and, therefore, are not included in the capital cost or owner's cost estimates.

10.1.3.6 Combustion Turbine O&M Cost Assumptions

- O&M cost estimates are provided based on an assumed capacity factor of 75 percent.
- Simple cycle units are assumed to start 200 times per year.
- Combined cycle units are assumed to start 50 times per year.
- Location was considered to be a greenfield site.
- Plant staff wage rates are based on an operator rate of $93,200 per year.
- Burden rate is 56 percent.
- Staff supplies and materials are estimated to be 5 percent of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs are estimated through at least one major overhaul.
- Combustion turbine combustion inspections, hot gas path inspections, and major overhauls are based on Original Equipment Manufacturer (OEM) pricing and recommendations.
- Steam turbine, generator, heat recovery steam generator and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data and recommendations.
- SCR was included for NO_x control for the simple cycle and combined cycle equipment.
- SCR uses 19 percent aqueous ammonia. Aqueous ammonia cost was estimated at $250/wet ton.
- Costs associated with a CO catalyst are included.
- Raw water costs are $0.77 per 1,000 gallons.
- Water treatment costs are included for water make-up and demineralized water where needed.
- Demineralized water treatment costs are $3.00 per 1,000 gallons.
- Station net capacity output is based on fired operation (duct burners) at annual average ambient conditions.
- The O&M analysis was completed in 2009 dollars.

10.1.3.7 Coal Facility O&M Cost Assumptions

- Fuel is pulverized coal.
- Net plant heat rate is 9,698 Btu/kWh.
- O&M cost estimates are based on an assumed gross capacity factor of 75 percent.
- O&M cost estimates assume the unit will start 50 times per year.
- Location was considered to be a greenfield site.
- Plant staff wage rates are based on an operator rate of $93,200 per year.

- Burden rate was 56 percent.
- Staff supplies and material are estimated to be 5 percent of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs are estimated through at least one major overhaul.
- Steam turbine, generator, boiler and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data and recommendations.
- SCR is included for NO_x control.
- SCR uses anhydrous ammonia with an estimated cost of $800/wet ton.
- Powdered activated carbon is included for mercury control.
- Activated carbon costs are estimated to be $1,600/ton.
- Dry Flue Gas Desulfurization (FGD) is used for SO_2 control.
- Dry FGD uses lime with an estimated cost of $75/ton.
- A fabric filter system is included for particulate control.
- Raw water costs are $0.77 per 1,000 gallons.
- Water treatment costs are included for cycle make-up and service water where needed.
- Cycle make-up water treatment costs are $5.00 per 1,000 gallons.
- The O&M analysis was completed in 2009 dollars.

10.1.4 Conventional Technology Options

The conventional technology supply-side options are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital costs, O&M costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

The conventional technologies considered include simple cycle combustion turbines, combined cycle configurations and a PC coal generating plant.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to these models. Rather, such assumptions were made to provide indicative output and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Power plant output and heat rate performance will degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit’s new and clean performance. The average degradation over the unit’s operating life that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed by Black & Veatch to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so technology-specific nonrecoverable output and heat rate factors have been developed and are presented in Table 10-2. The degradation percentages are applied one time to the new and clean performance data, and reflect average lifetime aggregate nonrecoverable degradation.

Table 10-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 1x1 6FA Combined Cycle	2.7	1.50
GE 2x1 6FA Combined Cycle	2.7	1.50

10.1.4.1 Simple Cycle Combustion Turbine Alternatives

Combustion turbine generators (CTGs) are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000ºF or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot (typically 900ºF to 1,100ºF) gases exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a “simple cycle” power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease due to the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit’s full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacity. Combustion turbine technology also provides rapid start-up and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

GE LM6000PC Combustion Turbine

The GE LM6000PC was selected as a potential simple cycle alternative due to its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a two-stage air-cooled high-pressure turbine (HPT), a five-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct-coupling to 3,600 revolutions per minute (rpm) generators for 60 hertz (Hz) power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold," end of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes
- Cycling or peaking operation
- Synchronous condenser capability
- Compact, modular design
- More than 5 million operating hours
- More than 450 turbines sold
- Dual fuel capability

The capital cost estimate was based on utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 10-3 presents the operating characteristics of the LM6000 combustion turbine. Water injection and high temperature SCR would be used to control NO_x to 3 ppmvd while operating on natural gas and on ULSD. Table 10-4 presents estimated emissions for the LM6000.

GE LMS100 Combustion Turbine

The LMS100 is a newer GE unit and has the disadvantage of not having as much commercial experience. As the LMS100 gains commercial acceptance, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an approximate efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated through additional LMS100 experience.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

Table 10-3
GE LM6000 PC Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (-10º F and 100% RH) (Full Load)	46.6	9,636
Winter (15º F and 68% RH) (Full Load)	47.5	9,662
Winter (15º F and 68% RH) (75% Load)	35.5	10,313
Winter (15º F and 68% RH) (50% Load)	23.5	11,791
Average (30º F and 68% RH) (Full Load)	47.6	9,741
Average (30º F and 68% RH) (75% Load)	35.6	10,365
Average (30º F and 68% RH) (50% Load)	23.6	11,828
Summer (59º F and 68% RH) (Full Load)	39.9	10,058

RH = Relative humidity.

(1)Net capacity and net plant heat rate include degradation factors.
(2)Net capacity and heat rate assume operation on natural gas.

Table 10-4
GE LM6000 PC Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0108
SO_2, lb/MBtu	0.0022
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

(1)Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR, water injection and CO catalyst.

There are two main differences between the LM6000 and the LMS100. The LMS100 cools the compressor air after the first stage of compression with an external heat exchanger and unlike the LM6000, which has an HPT and a power turbine, the LMS100 has an additional IPT to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800º F, which allows the use of a standard SCR system for NO_x control.

Table 10-5 presents the operating characteristics of the LMS100 combustion turbine. Standard SCR will be used to control NO_x to 3 ppmvd while operating on natural gas. Water injection and SCR will be used to control NO_x while operating on ULSD. Table 10-6 presents estimated emissions for the LMS100.

10.1.4.2 Combined Cycle Alternatives

Combined cycle power plants use one or more CTGs and one or more steam turbine generators to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. High pressure (HP) steam is produced when the hot exhaust gas from the CTG is passed through a heat recovery steam generator (HRSG). The HP steam is then expanded through a steam turbine, which spins an electric generator.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements due to added plant complexity.

1x1 GE 6FA Combined Cycle Alternative

The 1x1 combined cycle generating unit would include one GE 6FA CTG, one HRSG, one steam turbine generator, and an air cooled condenser. The combined cycle unit will be dual-fueled, with natural gas as the primary fuel and ULSD as the backup fuel.

The GE 6FA heavy-duty gas turbine is an aerodynamic scale of the GE 7FA. In the development of the turbine GE scaled a proven advanced-technology design and combined it with advanced aircraft engine cooling and sealing technology. The 6FA fleet has over two million operating hours logged with more than 100 units installed or on order. The 6FA gas turbine configuration includes an 18-stage compressor, six combustion chambers and a three-stage turbine. The shaft is supported on two bearings. The combustion system standard offering includes dry low NO_x burners capable of multi-fuel applications.

The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the steam turbine generator. The HRSG is expected to be a natural circulation, three pressure, reheat unit. The combined cycle alternative will be designed for supplemental duct firing (on natural gas only). Supplemental firing necessitates a larger steam turbine and changes to other plant components, leading to an increase in total capital cost and a decrease in plant efficiency in order to realize the additional output. SCR and dry low-NO_x burners will be included to control NO_x to 3 ppmvd while burning natural gas, and a CO catalyst will be included to reduce emissions. Water injection will be used for NO_x control when burning ULSD.

Table 10-5
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (-10º F and 100% RH) (Full Load)	95.3	8,894
Winter (15º F and 68% RH) (Full Load)	95.5	8,925
Winter (15º F and 68% RH) (75% Load)	71.4	9,445
Winter (15º F and 68% RH) (50% Load)	47.3	10,489
Winter (15º F and 68% RH) (Min Load)	35.7	11,444
Average (30º F and 68% RH) (Full Load)	96.0	8,963
Average (30º F and 68% RH) (75% Load)	71.8	9,456
Average (30º F and 68% RH) (50% Load)	47.6	10,501
Average (30º F and 68% RH) (Min Load)	36.3	11,415
Summer (59º F and 68% RH) (Full Load)	97.4	9,041

RH = Relative humidity.

[1]Net capacity and net plant heat rate include degradation factors.
[2]Net capacity and heat rate assume operation on natural gas.

Table 10-6
GE LMS100 Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0108
SO_2, lb/MBtu	0.0022
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

[1]Emissions are at full load at 30º F, and include the effects of SCR, water injection and CO catalyst.

The steam turbine is based on a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one intermediate-pressure (IP) section, and a two-flow low-pressure (LP) section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine.

Table 10-7 presents the operating characteristics of the 1x1 GE 6FA combined cycle generating unit. Table 10-8 presents estimated emissions for the 1x1 GE 6FA combined cycle generating unit.

2x1 GE 6FA Combined Cycle Alternative

The 2x1 combined cycle generating unit would include two GE 6FA CTG, two HRSGs, one steam turbine generator, and an air cooled condenser. The combined cycle unit will be dual-fueled, with natural gas as the primary fuel and ULSD as the backup fuel.

The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the steam turbine generator. The HRSG is expected to be a natural circulation, three pressure, reheat unit. The combined cycle alternative will be designed for supplemental duct firing (on natural gas only). SCR and dry low- NO_x burners will be included to control NO_x to 3 ppmvd while burning natural gas, and a CO catalyst will be included to reduce emissions. Water injection will be used for NO_x control when burning ULSD.

The steam turbine is based on a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine.

Table 10-9 presents the operating characteristics of the 2x1 GE 6FA combined cycle generating unit. Table 10-10 presents estimated emissions for the 2x1 GE 6FA combined cycle generating unit.

10.1.4.3 Coal Technologies

The coal technology presented in this technology assessment includes a subcritical PC generating facility. Other coal technologies such as integrated gasification combined cycle (IGCC) or carbon capture and sequestration (CCS) could also be considered, but those technologies have not developed to a point where they have significantly penetrated the coal generation market. In addition, generating costs from these technologies generally exceed those of PC's. Therefore, this technology assessment provides estimates of the performance and cost for the PC alternative.

Subcritical Pulverized Coal (PC) (130 MW)

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate a single unit size of up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

Table 10-7
GE 1x1 6FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]		Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]	
	Fired	Unfired	Fired	Unfired
Winter (-10º F and 100% RH) (Full Load)	161.3	120.8	7,814	7,581
Winter (15º F and 68% RH) (Full Load)	153.7	118.1	7,770	7,307
Winter (15º F and 68% RH) (75% Load) [3]		115.1		7,290
Winter (15º F and 68% RH) (50% Load) [3]		76.6		8,288
Winter (15º F and 68% RH) (Min Load) [3]		50.6		9,187
Average (30º F and 68% RH) (Full Load) [3]	150.4	113.8	7,751	7,418
Average (30º F and 68% RH) (75% Load) [3]		112.7		7,426
Average (30º F and 68% RH) (50% Load) [3]		75.4		8,047
Average (30º F and 68% RH) (Min Load) [3]		48.5		9,531
Summer (59º F and 68% RH) (Full Load)	143.0	110.6	7,768	7,282

RH = Relative humidity.
[1]Net capacity and net plant heat rate include degradation factors
[2]Net capacity and heat rate assume operation on natural gas.
[3]Part load performance percent load is based on gas turbine load point.

Table 10-8
GE 1x1 6FA Combined Cycle Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0109
SO_2, lb/MBtu	0.0020
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

[1]Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

Table 10-9
GE 2x1 6FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]		Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]	
	Fired	Unfired	Fired	Unfired
Winter (-10º F and 100% RH) (Full Load)	325.0	248.4	7,755	7,374
Winter (15º F and 68% RH) (Full Load)	310.2	237.6	7,698	7,264
Winter (15º F and 68% RH) (75% Load) [3]		229.8		7,366
Winter (15º F and 68% RH) (50% Load) [3]		154.9		8,089
Winter (15º F and 68% RH) (Min Load) [3]		99.4		9,335
Average (30º F and 68% RH) (Full Load) [3]	303.9	231.9	7,684	7,281
Average (30º F and 68% RH) (75% Load) [3]		227.6		7,283
Average (30º F and 68% RH) (50% Load) [3]		151.7		7,996
Average (30º F and 68% RH) (Min Load) [3]		99.6		9,277
Summer (59º F and 68% RH) (Full Load)	289.2	222.9	7,698	7,224

RH = Relative humidity.
[1]Net capacity and net plant heat rate include degradation factors
[2]Net capacity and heat rate assume operation on natural gas.
[3]Part load performance percent load is based on gas turbine load point.

Table 10-10
GE 2x1 6FA Combined Cycle Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0109
SO_2, lb/MBtu	0.0020
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

[1]Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psig, compared to the steam pressure of 2,400 psig for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psig) to supercritical (3,500 psig) generally improves the net plant heat rate by about 200 Btu/kWh (higher heating value [HHV]), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

The subcritical PC generating unit characterized here includes a single steam turbine generator and subcritical PC boiler fueled by low-grade sub-bituminous coal. Air quality control systems include low- NO_x burners, SCR for NO_x control, dry FGD for SO_2 control, activated carbon injection for mercury control, and fabric filters for particulate control. Heat rejection is accomplished by an air cooled condenser.

Table 10-11 presents the operating characteristics of the subcritical PC generating unit and Table 10-12 presents the estimated.

10.1.4.4 Conventional Technology Alternatives Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The estimated capital costs, O&M costs, schedules, forced outage, and maintenance assumptions for the conventional alternatives are summarized in Table 10-13. All costs are provided in 2009 dollars. The EPC cost is inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. Owner’s costs were developed using the previously described assumptions, with site-specific cost additions or reductions as discussed previously. The assumed owner’s cost allowance is representative of typical owner’s costs, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses. Owner’s costs are specific to individual projects and may change from those presented in Table 10-13.

Fixed and variable O&M costs are also provided in 2009 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Variable costs include outage maintenance, consumables, and replacements dependent upon unit operation. Construction schedules are indicative of typical construction durations for the alternative technologies and plant sizes and represent estimated schedules from receipt of notice-to-proceed to commercial operation. Actual construction schedules will depend upon equipment delivery schedules, which are highly market driven, and therefore may be longer than those presented in Table 10-13. Actual costs may also vary from the estimates provided in Table 10-13.

The annual average scheduled and forced outage assumptions for the generating alternatives are also presented in Table 10-13. The scheduled forced outages represent the average outage through a complete maintenance cycle.

Table 10-11
Subcritical PC Thermal Performance Estimates

Ambient Condition	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (-10º F and 100% RH) (Full Load)	128.1	9,830
Winter (15º F and 68% RH) (Full Load)	128.1	9,834
Winter (15º F and 68% RH) (75% Load)	96.0	10,143
Winter (15º F and 68% RH) (50% Load)	64.0	12,030
Winter (15º F and 68% RH) (Min Load)	51.2	12,246
Average (30º F and 68% RH) (Full Load)	128.1	9,843
Average (30º F and 68% RH) (75% Load)	96.0	10,109
Average (30º F and 68% RH) (50% Load)	64.0	11,734
Average (30º F and 68% RH) (Min Load)	51.2	12,547
Summer (59º F and 68% RH) (Full Load)	128.1	10,004

RH = Relative humidity.

[1]Net capacity and net plant heat rate include an applied 1.5% degradation factor.
[2]Net capacity and heat rate assume operation on a bituminous coal and petcoke blend.

Table 10-12
Subcritical PC Estimated Air Emissions[1]

NO_x, lb/MBtu	0.05
SO_2, lb/MBtu	0.06
CO_2, lb/MBtu	212
CO, lb/MBtu	0.10
PM_{10}, lb/MBtu	0.018

[1]Emissions are at full load at 30º F, reflect operation on sub-bituminous coal. All estimates are presented on the basis of HHV.

Table 10-13
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives (All Costs in 2009 Dollars)

Supply Alternative	EPC Cost ($Millions)[1]	Owner's Cost ($Millions)[2]	Total Cost ($Millions)	Full Load Net Capacity at 70° F (MW)	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr) at 70° F	Variable O&M ($/MWh)	Construction Schedule (Months)[3]	Scheduled Maintenance (days)	Forced Outage (percent)
GE LM6000 SC	49.71	12.43	62.14	49.2	1,263	64.41	3.85	21	10	2
GE LMS100 SC	100.54	25.14	125.68	99.2	1,267	32.5	3.08	24	10	2
1x1 GE 6FA CC w/ Supplemental Firing	259.11	64.78	323.89	154.6	2,095	24.61	2.71	30	14	3
2x1 GE 6FA CC w/ Supplemental Firing	409.20	102.30	511.50	312.3	1,638	16.12	2.61	30	14	3
130 MW sub-critical PC	688.30	206.49	894.79	130.1	6,878	100.89	2.59	62	16	5

(1)EPC costs include SCR, CO catalyst, and dual fuel capability as applicable to each alternative.
(2)Owner's costs are specific to individual projects and may change from those presented.
(3)Construction schedules will depend upon equipment delivery schedules, which are highly market driven, and therefore may be longer than those presented.

10.2 Beluga Unit 8 Repowering

Currently, Chugach Electric plans to retire its Beluga Generation Unit Number 8, which is the steam turbine unit at the Beluga 2x1 combined cycle facility, at the end of 2014. As an alternative to building new gas fired generation, Chugach identified an option that would include rebuilding Unit 8 and continuing to operate the Beluga Generation plant in combined cycle mode through the end of 2034. The rebuild would occur over a three year period from 2014 through 2016 with a total cost of $50 million.

10.3 GVEA North Pole 1x1 Retrofit

GVEA identified an opportunity for a combined cycle retrofit at the existing North Pole combined cycle facility. The 1x1 North Pole combined cycle facility was built to accommodate another 1x1 train and the steam turbine is already sized for a 2x1. The retrofit involves adding an LM6000 and a heat recovery steam generator to the existing facility. The new 1x1 combined cycle train has a maximum capacity of 64 MW and a full load heat rate of 8,270 Btu/kWh. The capital cost for the retrofit has a total cost of $83 million in 2009 dollars. The variable O&M for the unit is modeled at $2.19/MWh. Since the fixed O&M costs are already modeled in the existing North Pole combined cycle unit, they are set at $0/kW-yr for the retrofitted unit.

10.4 Renewable Energy Options

10.4.1 Hydroelectric Project Options

Hydroelectric power is currently the Railbelt's largest source of renewable energy, responsible for approximately 9 percent of the Railbelt's electrical energy. Many of the State's developed hydro resources are located near communities in Southcentral, the Alaska Peninsula, and Southeast. Hydro projects include those that involve storage, both with and without dam construction, and smaller "run-of-river" projects. A number of potential hydro projects exist within or near the Railbelt region. The locations for the projects shown below represent either the service area in which the project is located or the transmission area shown in Figure 4-1 in which the project is interconnected to the Railbelt grid.

- Susitna - 380 – 1,880 MW, MEA
- Glacier Fork – 75 MW, MEA
- Chakachamna – 330 MW, Chugach (Anchorage)
- South Fork/Eagle River – 1 MW, MEA
- Fishhook – 2 MW, MEA
- Grant Lake/Falls Creek – 5 MW, Kenai
- 7 Other Small Hydro Projects in AEA's database

In addition, the developers of several proposed hydro projects (each with $5 million or above estimated project cost) on the Railbelt have applied for grant requests from the AEA Renewable Energy Fund Grant Program, which was established by Alaska Legislature in 2008. Table 10-14 shows each proposed hydro project's name, applicant, estimated project cost, grant requested, funding decision and amount recommended by AEA after two rounds of ranking and funding allocations conducted by AEA.

Based on review of the above information and discussion with stakeholders including the Railbelt Utilities, Black & Veatch assumed that the proposed Susitna, Chakachamna, and Glacier Fork projects will be considered as potential supply-side alternatives in this RIRP study along with a 5 MW generic hydro unit in the Kenai and a 2 MW generic hydro unit in MEA's service area. The following subsections discuss further details of these proposed projects.

Table 10-14
AEA Recommended Funding Decisions - Hydro

Project Name	Applicant	Project Cost ($000)	Grant Requested ($000)	Recommended Funding Decision	Recommended Funding Amount ($000)
Grant Lake/Falls Creek Hydro Feasibility Study	Kenai Hydro, LLC	$26,924	$816	Full funding	$816
Fourth of July Creek Hydro Reconnaissance	Independence Power, LLC	$15,675	$7,838	Partial funding	$20
Victor Creek Hydro(1)	Kenai Hydro, LLC	$19,860	$88	Full funding	$88
Glacier Fork Hydro	Glacier Fork Hydro, LLC	$330,000	$5,000	Partial funding	$500
Archangel Creek Hydro	Archangel Green Power, LLC	$6,420	$100	Not recommended(2)	None
Nenana Healy Hydro Phase II	GVEA	$24,000	$2,200	Application Withdrawn	None

Note:
1. Project failed to get funding after the appropriation for Round 2 was limited to $25 million.
2. The project did not pass Stage 2 review or was excluded in Stage 3 review for geographical spreading.

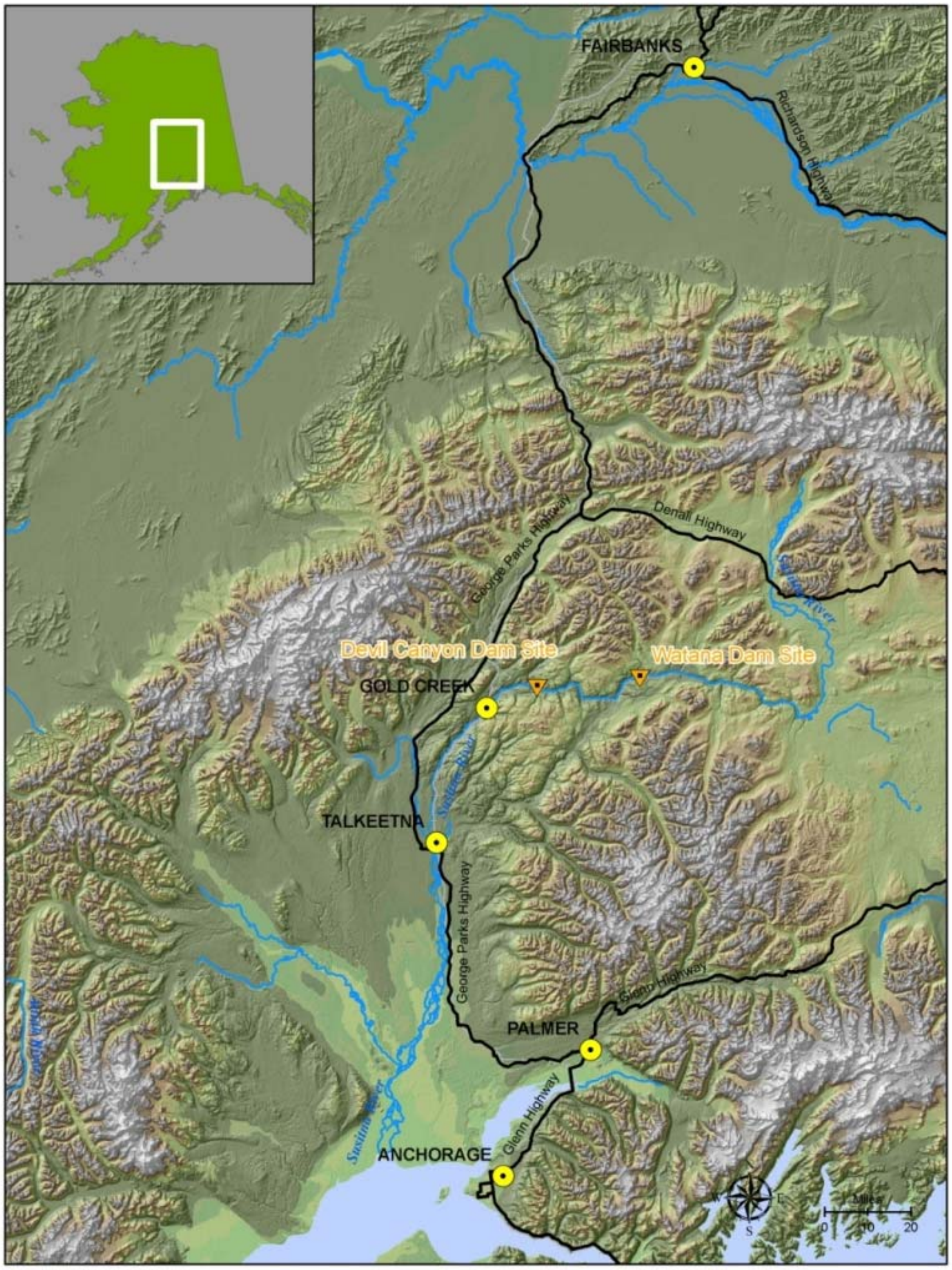
10.4.1.1 Susitna Project

Description of Project

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. The project's location is shown in Figure 10-1.

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.

Figure 10-1
Proposed Susitna Hydro Project Location
(Source: HDR)



HDR was contracted by AEA to update the cost estimate, energy estimates and the project development schedule for a Susitna River hydroelectric project. The results of that study, except for the detailed appendices, are included in Appendix A (note: one of the detailed appendices in the HDR Report [Appendix D], which is not included in Appendix A of this report, addresses the issue of the potential impact of climate changes on Susitna's resource potential; this appendix can be viewed in the full HDR report which is available on the AEA web site).

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:

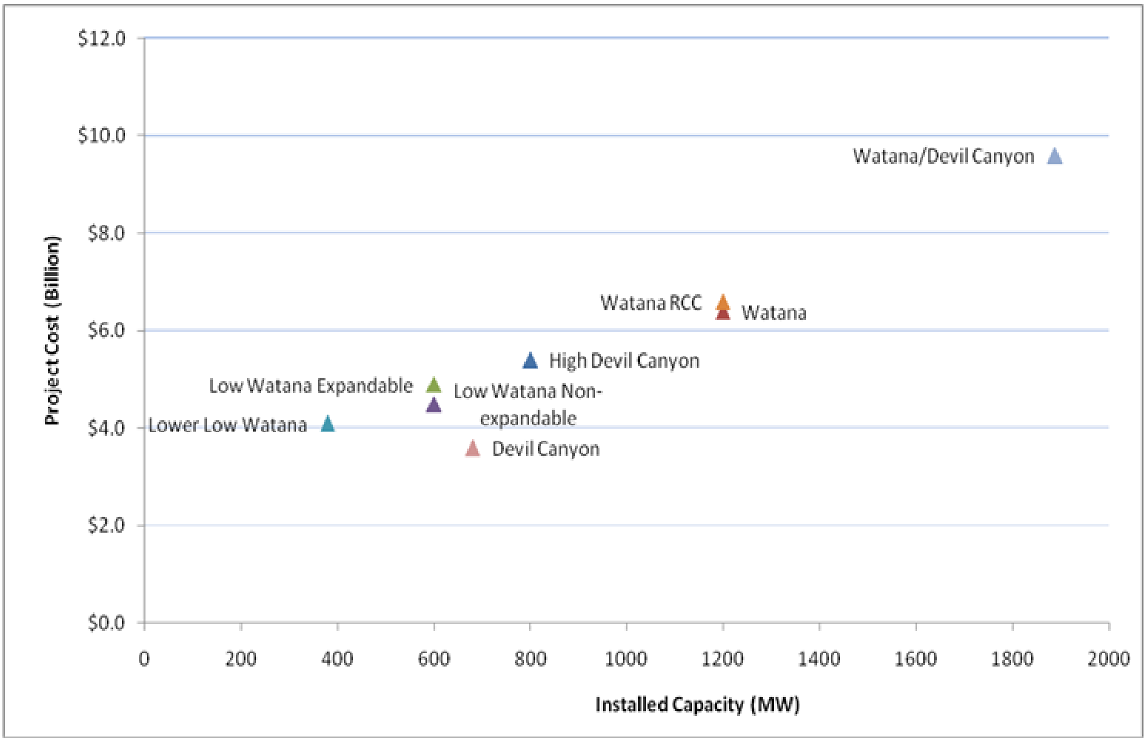
- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing four turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative 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 10-15 and a comparison of project size versus project cost is shown in Figure 10-2.

Table 10-15
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 10-2
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.

Mode of Operation

All of the alternatives identified have significant storage capability which enhances their benefits to the Railbelt Utilities. Table 10-16 presents the average annual and average monthly generation from each of the alternatives.

Capital Costs

The estimated capital costs for the alternative Susitna projects are presented in Table 10-15. For evaluation purposes, the capital cost for the Low Watana expansion to Watana is estimated as the difference in costs between Watana and Low Watana (Expansion) since it was not part of HDR's scope and they did not explicitly develop the cost for expansion.

Table 10-16
Average Annual Monthly Generation from Susitna Projects (MWh)

Alternative	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Lower Low Watana (non-expandable)	2,006,000	127,000	116,000	127,000	117,000	101,000	208,000	270,000	28,000	256,000	153,000	123,000	128,000
Low Watana (non-expandable)	2,617,000	182,000	166,000	183,000	176,000	119,000	241,000	334,000	378,000	315,000	157,000	180,000	186,000
Low Watana (expandable)	2,617,000	182,000	166,000	183,000	176,000	119,000	241,000	334,000	378,000	315,000	157,000	180,000	186,000
Watana	3,676,000	280,000	254,000	279,000	261,000	498,000	443,000	370,000	326,000	237,000	169,000	275,000	284,000
High Devil Canyon	3,891,000	262,000	235,000	257,000	247,000	287,000	382,000	468,000	522,000	467,000	251,000	252,000	261,000
Low Watana (Expansion)	1,059,000	73,648	67,174	74,053	71,220	48,155	97,524	135,157	152,962	127,468	63,532	72,839	75,267

O&M Costs

O&M costs include fixed and variable costs. Fixed O&M costs for the Susitna hydro projects vary based on the number of turbines, transformers, and dams in each specific project. A schedule and cost estimate of major maintenance items were provided by HDR through time.

Schedule

HDR provided development schedules for the original Susitna alternatives as shown in Table 10-15.

10.4.1.2 Chakachamna Project

Description of Project

TDX Power, Incorporated (TDX) is developing a hydro project on the Chakachamna River system. The proposed project will divert stream flow via a lake tap from the Chakachamna River to a powerhouse on the McArthur River via a 25 foot diameter power tunnel that will be approximately 10 miles long. The project will be located approximately 42 miles from Chugach's Beluga power generating facility. Figure 10-3 illustrates the proposed project's location. According to TDX, the proposed project will have an installed capacity of 330 MW, and will be able to generate approximately 1,600 GWh of electricity annually. Table 10-17 shows the average monthly and annual energy that will be generated by the project.

Figure 10-3
Proposed Chakachamna Hydro Project Location
(Source: TDX)

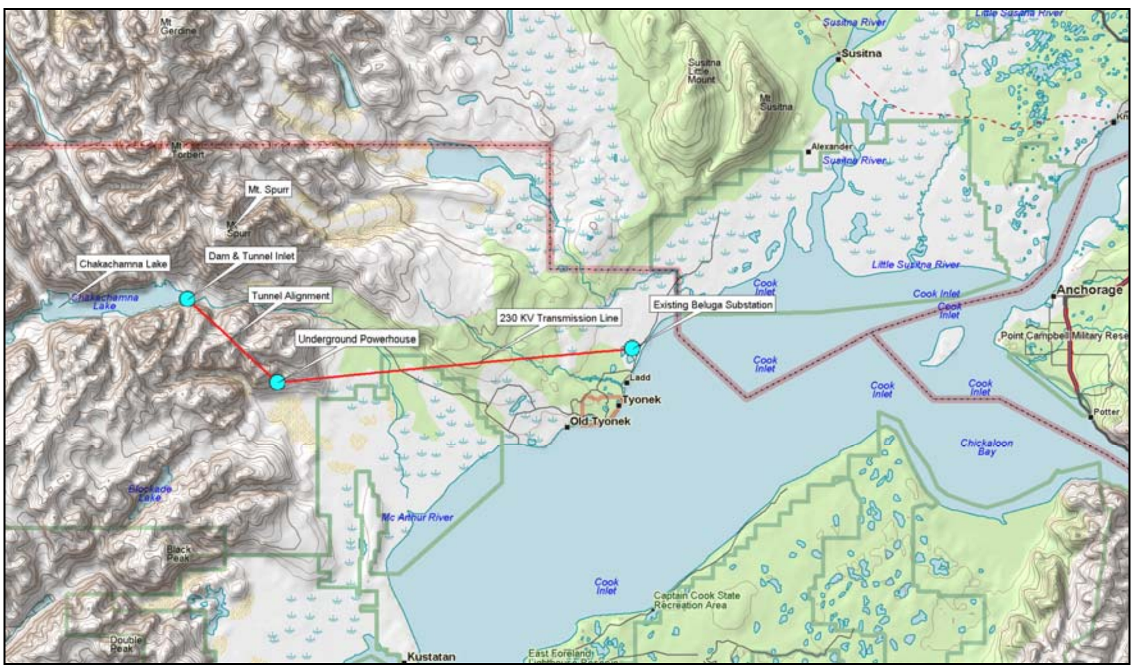


Table 10-17
Monthly Average and Annual Generation

Month	Generation (GWh)
January	163
February	140
March	138
April	120
May	113
June	106
July	108
August	113
September	120
October	142
November	158
December	177
Total	**1,598**

The project will not require the construction of a dam on the Chakachamna Lake, but fish gates will be installed at the outlet of the lake. The reservoir has approximately 16,700 acres of water surface at an elevation of 1,142 feet. Other facilities that will be constructed include fish passage facilities for adult migration and juvenile outmigration, a 42-mile transmission line from the project site to Chugach's Beluga substation, and site access.

Mode of Operation
It is expected that this project will be designed and permitted as a diverted flow type hydroelectric generating facility.

Capital Costs
According to TDX, the total capital cost of the proposed project will be approximately $1.6 billion in 2008 dollars or $5,100/kW in 2009 dollars. Transmission costs of $58 million are included in capital costs.

O&M Costs
O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation.

According to TDX, the total O&M cost for the proposed project will be approximately $10 million per year in 2008 dollars or $30/kW-Yr in 2009 dollars.

For the purpose of this study, Black & Veatch assumes that the variable O&M costs will be zero, and the fixed O&M costs will be $30/kW-Yr in 2009 dollars.

Schedule
Base on the schedule provided by TDX in their April 2009 presentation, TDX expects that the proposed hydro generating project could be available for commercial operations starting in 2017.

10.4.1.3 Glacier Fork

Description of Project
The proposed Glacier Fork project is a 75 MW hydroelectric project being developed by Glacier Fork Hydropower LLC on the Knik River, approximately 25 miles southeast of Palmer in the Matanuska-Susitna Borough.

According to information provided by Glacier Fork Hydropower LLC, the project would consist of: 1) a proposed 800-foot-long, 430-foot-high dam; 2) a proposed reservoir having a surface area of 390 acres and a storage capacity of 75,000 acre-feet and normal water surface elevation of 980 feet above mean low sea level (msl); 3) a proposed 8,300-foot-long, 12-foot diameter steel penstock; 4) a proposed powerhouse containing three generating units having an installed capacity of 75 MW; 5) a proposed tailrace; 6) a proposed 25-mile-long, 115-kilovolt transmission line; and 7) appurtenant facilities.

The proposed Glacier Fork Hydroelectric Project would have an average annual generation of 330 GWh. The estimated average monthly generation is presented in Table 10-18.

Table 10-18
Glacier Fork Hydroelectric Project
Average Monthly Energy Generation

Month	Average Monthly Energy (MWh)
Installed Capacity (MW)	75
January	6,755
February	5,314
March	4,882
April	6,727
May	28,794
June	53,612
July	55,400
August	55,400
September	53,305
October	35,964
November	13,767
December	7,617
Annual Total (MWh)	327,538

Note: Data based on USGS Gauge on Knik River.

Mode of Operation

As indicated in Table 10-18, the Glacier Fork project is primarily a run-of-river project with the ability to provide firm capacity significantly reduced from its nameplate ratings during winter and spring. This reduced output during these periods was included in the Strategist® and PROMOD® modeling.

Capital Costs

The total capital cost of the proposed project will be approximately $4,400/kW, or $330 million, in 2009 dollars. Transmission costs are assumed to be $22.5 million (25 miles, 115 kV @ $900K/mile) and are included in capital cost.

Operation and Maintenance Cost

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation.

The total O&M cost for the proposed project will be approximately $68/kW-Yr in 2009 dollars. For the purpose of this study, Black & Veatch assumed that the variable O&M costs will be zero, and the fixed O&M costs will be $68/kW-Yr in 2009 dollars.

Schedule

Based on information provided by Glacier Fork Hydropower LLC, the proposed hydro generating project could be available for commercial operations starting Fall 2014 at the earliest.

10.4.1.4 Generic Hydroelectric Projects

Black & Veatch developed two small, generic hydroelectric project alternatives to represent several hydroelectric opportunities that have been identified in the Railbelt. The first hydroelectric project is a 5 MW project located in the Kenai area. The project is assumed to have 20 GWh of average annual energy with a capital cost of $35 million in 2009 dollars. The other generic project is a 2 MW project located in MEA's area. The MEA project is assumed to have an average annual energy of 7.5 GWh and a capital cost of $16 million in 2009 dollars.

10.4.2 Ocean (Tidal Wave) Project Option

Alaska has a wide coastal area that allows for the consideration of renewable tidal resources. The Cook Inlet in particular offers a great potential for tidal projects since it has the fourth highest tide in the world with 25 feet (7.6m) between low tide and high tide. Also, it is located between Anchorage, Alaska's largest city, and Kenai, where a number of industries are located.

Some institutions are already interested in taking advantage of this resource in this particular location and have started studies and licensing for tidal projects including the Turnagain Arm Tidal Electric Generation Project.

There are several different technologies available for tidal projects. Based on Black & Veatch's review of available information, we assumed that the proposed Turnagain Arm tidal project would be representative of the technologies available, although it is Black & Veatch's opinion that tidal energy is not to the level of commercialization equivalent to other conventional and renewable alternatives considered in the RIRP. The ultimate selection of the optimal technology for Railbelt conditions will need to be based on additional analysis. As a result, tidal energy will be considered as a sensitivity case in the evaluations. The following subsections discuss further details of the proposed project.

10.4.2.1 Turnagain Arm

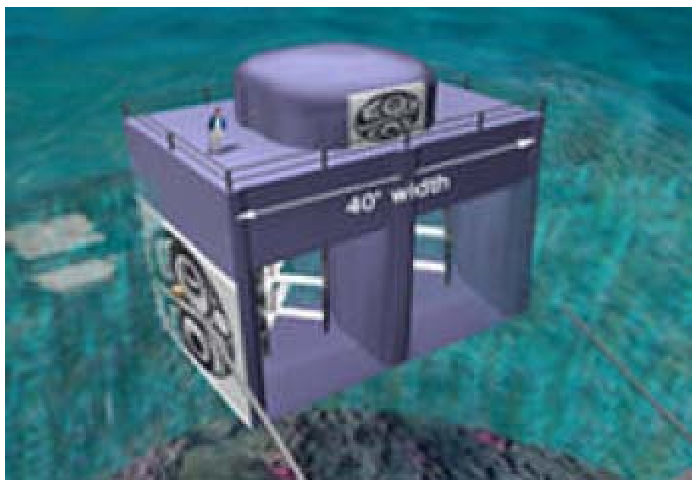
Description of Project
Little Susitna Construction Co. and Blue Energy Canada filed an application for a preliminary FERC permit for the Turnagain Arm Tidal Project, to be developed in Cook Inlet.

According to the preliminary permit application, the project calls for the use of Blue Energy's Tidal Bridge which will use the Davis Turbine to generate electricity with the movement of the tides. The Davis Turbine is a mechanical device that employs a hydrodynamic lift principle, causing vertically oriented foils to turn a shaft and a generator. Figure 10-4 shows an array of vertical-axis tidal turbines stacked and joined in series across a marine passage.

Figure 10-4
Blue Energy's Tidal Bridge With Davis Turbine
(Source: Blue Energy)

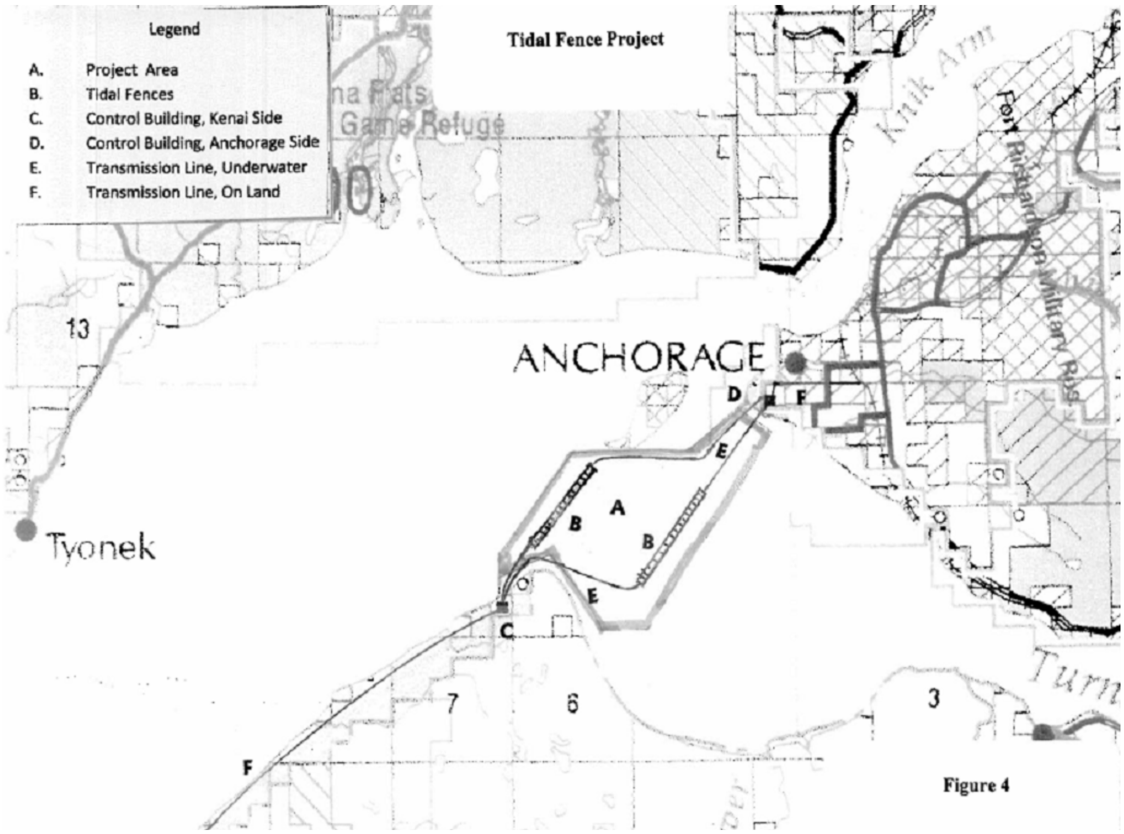
This turbine is comprised of vertical hydrofoils attached to a central shaft transmitting torque to a generator. The kinetic energy from tidal flows can thus be harnessed and converted to electrical energy. Contrary to the traditional drag driven paddle wheel design, the Davis turbine rotor is designed to be lift driven, much like the modern wind turbines, thus allowing the blades to operate at a significantly higher efficiency. In order to further increase the efficiency of the turbine, the entire rotor assembly is housed in a thin-shell marine concrete caisson structure that channels the water flow and acts as a housing for the generator and electrical components. The shape of the caisson inner walls accelerate the velocity of the water flow through the turbine rotor by acting as a venturi and controls flow direction to provide more uniform turbine performance. In addition, the Davis turbine is designed to work through the entire tidal range with a typical cut-in speed of 1m/s. Figure 10-5 shows the configuration of a Davis tidal turbine.

Figure 10-5
Cutaway Graphic of a Mid-Range-Scale Vertical Axis Tidal Turbine
(Source: Blue Energy)



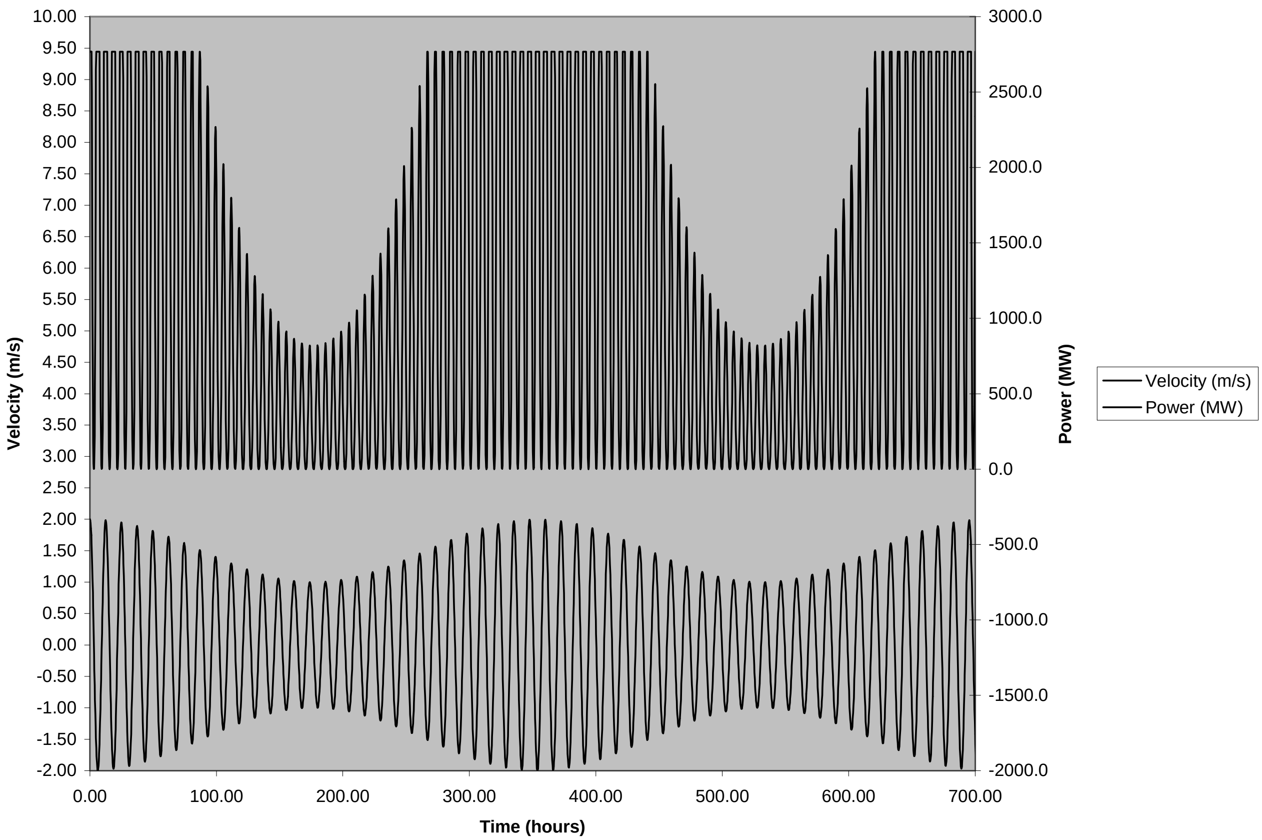
The Turnagain Arm tidal project would be comprised of two tidal fences each eight miles long extending from Kenai to Anchorage, with minimum separation of five miles to allow the tidal force to recover its strength after going through the first fence. The tidal fence will have a service road across the top and connected to the land. Two control buildings would be required, one located near Possession Point in Kenai Borough and the other along Raspberry Road in Anchorage. They will be connected by a pair of transmission lines across the tidal fence and connect to the HEA grid on the Kenai side and to the Chugach grid on the Anchorage side. From there, the power can be moved throughout the Railbelt grid. Figure 10-6 depicts the proposed layout of the tidal plant.

Figure 10-6
Proposed Layout of the Turnagain Arm Tidal Project
(Source: Little Susitna Construction Co. and Blue Energy of Canada)



Mode of Operation
Tidal energy while fairly predictable is very variable. Black & Veatch conducted a high level analysis of the monthly generation from the Turnagain Arm tidal project. That analysis is presented in Figure 10-7.

Figure 10-7
Turnagain Arm Tidal Project Monthly Generation



As discussed for the large Susitna options, the capacity of the Turnagain Arm tidal project significantly exceeds the Railbelt loads. For evaluation purposes, Black & Veatch modeled a 100 MW project with following $/kW cost.

Capital Costs
Capital costs of $2.5 billion in 2009 dollars for the 1,200 MW Turnagain Arm tidal project or approximately $2,100/kW are expected, including supporting infrastructure. Black & Veatch's experience with the development of similar projects indicates that the Turnagain Arm tidal project costs are significantly lower than other projects that Black & Veatch has worked with. For evaluation purposes, Black & Veatch has used a capital cost of $4,200/kW.

O&M Costs
O&M costs include fixed and variable costs.

Fixed O&M Costs
Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. For the purpose of this study, the fixed O&M costs associated with the project are estimated to be $42 /kW-year in 2009 dollars.

Variable O&M
Variable O&M costs include consumables, chemicals, lubricants, major inspections, and overhauls of the turbine generators and associated equipment. Variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch has assumed no Variable O&M costs for this project.

Schedule
Black & Veatch expects that the proposed tidal generating project will be available for commercial operations starting in 2020 at the earliest.

10.4.3 Geothermal Project Option

Description of Project
Ormat Technologies, Inc (Ormat) has approached the AEA for the potential development of a geothermal power plant project at Mount Spurr, which is located approximately 33 miles from Tyonek, Alaska. According to Ormat, there is the potential geothermal resource to develop a geothermal power plant project with an estimated maximum output of 50–100 MW at Mount Spurr.

Depending on the specific resource conditions available at Mount Spurr, the proposed geothermal project option will likely be based on either a binary geothermal power plant configuration or a geothermal combined cycle power plant configuration.

Figure 10-8 illustrates a simplified binary geothermal power plant process diagram. A geothermal fluid (brine, or steam, or a mixture of brine and steam) from an underground reservoir can be used to drive a binary plant. The geothermal fluid flows from the wellhead to heat exchangers through pipelines. The fluid is used to heat and vaporize a secondary working fluid in the heat exchangers. The secondary working fluid is typically an organic fluid with a low boiling temperature point. The generated vapors are used to drive an organic vapor turbine, which powers the generator, and then are condensed in a dry cooled or wet cooled condenser. The condensed secondary fluid is then recycled back into the heat exchangers by a pump while the geothermal fluid is re-injected into the reservoir.

Figure 10-9 illustrates a simplified geothermal combined cycle power plant process diagram. A geothermal combined cycle is most effective when the available geothermal resource is mostly steam. The high-pressure steam from a separator drives a back pressure turbine. The low-pressure steam exits this turbine at a positive pressure and flows into the vaporizer. The heat of condensation of the low-pressure steam is used to vaporize a secondary working fluid and the expansion of these secondary fluid vapors drives the secondary turbine. The secondary fluid vapors are then condensed, and pumped back into the pre-heater and the geothermal fluid is re-injected into the reservoir.

For the purpose of this study, Black & Veatch assumed that the proposed geothermal project can be developed in two 50 MW blocks.

Figure 10-8
Simplified Binary Geothermal Power Plant Process
(Source: Ormat)

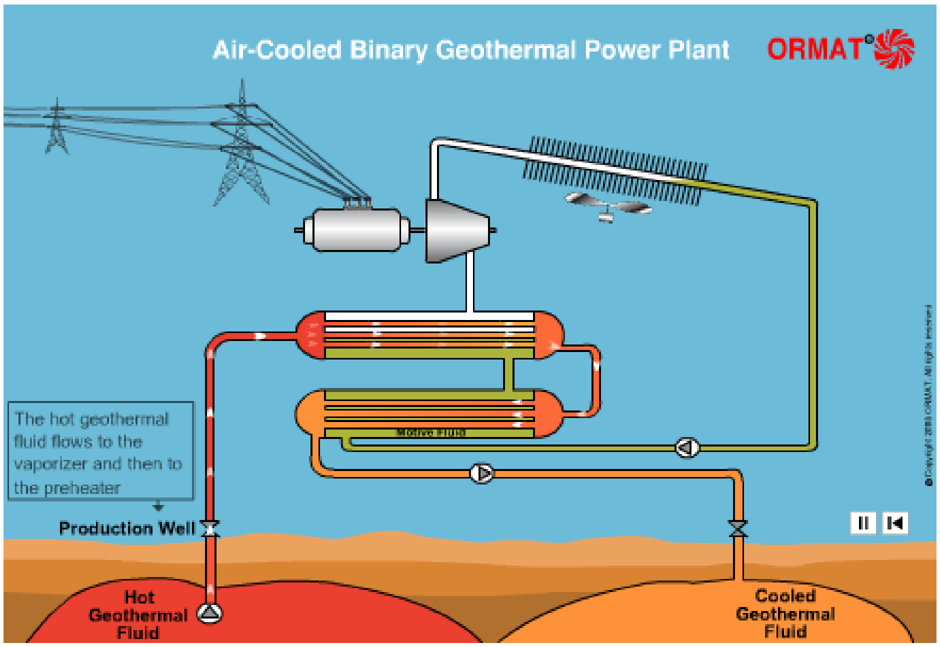
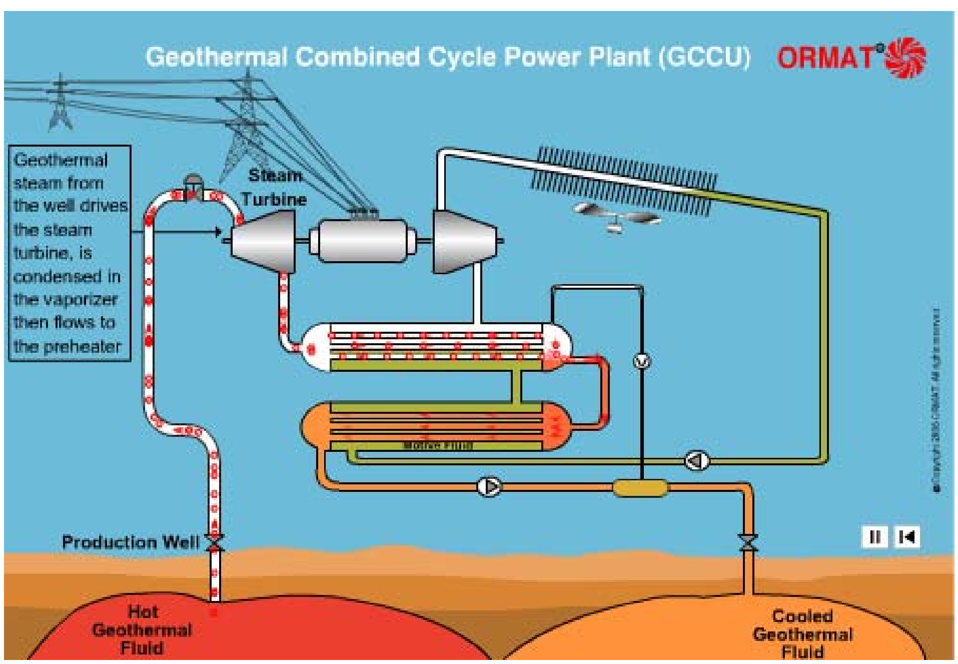


Figure 10-9
Simplified Geothermal Combined Cycle Power Plant Process
(Source: Ormat)



Mode of Operation

It is expected that the geothermal power plant project will be designed and permitted for baseload operations. Black & Veatch assumed that the proposed geothermal plant will be able to achieve 95 percent availability factor during its first commercial operation year and will experience approximately 0.5 percent output degradation annually for the following nine years until new wells are drilled to replace old wells. Black & Veatch also assumed that the estimated cost for drilling a new well to replace an old well will be approximately $2 million per well in 2009 dollars.

Based on the above assumptions and for the purpose of this study, Black & Veatch assumed that the proposed geothermal plant will operate at an average capacity factor of approximately 90 percent for 30 years, with an estimated levelized well drilling and replacement cost of $20/kW-year.

Capital Costs

Ormat did not provide estimated capital cost data for review by Black & Veatch. For the purpose of this study, Black & Veatch assumed that the construction cost for the first block of the proposed geothermal project will be approximately $4,000/kW in 2009 dollars. Black & Veatch assumed that this cost includes engineering, procurement, and construction costs for equipment, materials, construction contracts, and other indirect costs. Black & Veatch assumed that owner's cost items such as land, contingency, etc., will be approximately $1,000/kW in 2009 dollars, or 25.0 percent of the project construction cost. Therefore, it is anticipated that the total capital cost for the proposed project will be approximately $5,000/kW in 2009 dollars. The capital cost for the second block is assumed to be 10 percent less than the first block.

O&M Costs

O&M costs include fixed and variable costs.

Fixed O&M Costs

Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. Therefore, for the purpose of this study the fixed O&M costs associated with the project are estimated to be $300/kW-year in 2009 dollars.

Variable O&M Costs

Variable O&M costs include consumables, chemicals, lubricants, water, major inspections, and overhauls of the steam turbine generator and associated equipment. Variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $2.00/MWh in 2009 dollars.

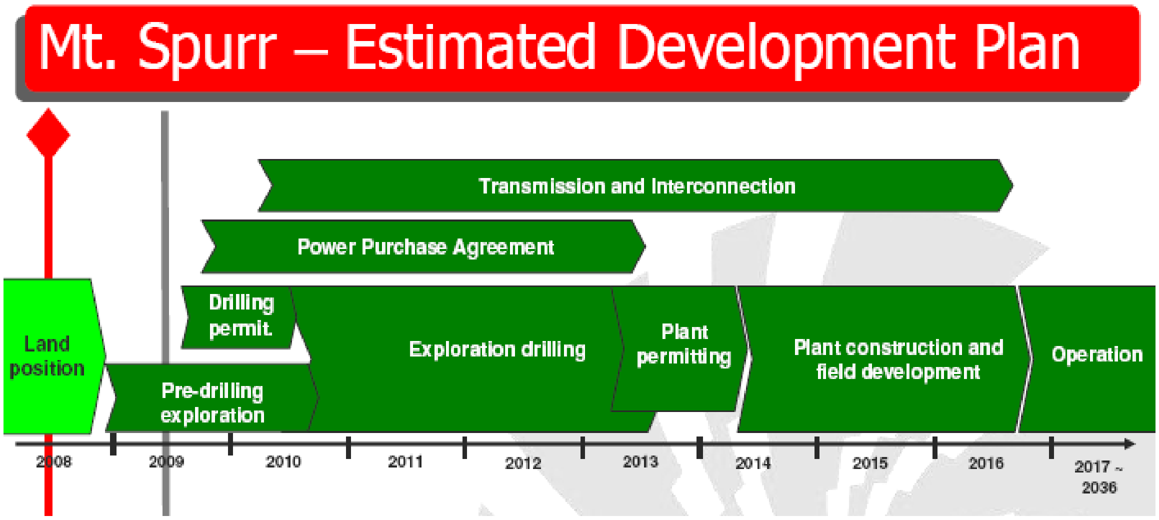
Availability Factor

Availability factor is a measure of the availability of a generating unit to produce power considering operational limitations such as unexpected equipment failures, repairs, routine maintenance, and scheduled maintenance activities. For the purpose of this study, Black & Veatch assumed that the initial availability factor of this proposed geothermal plant will be 95 percent.

Schedule

Figure 10-10 illustrates the estimated project development plan that Ormat presented to AEA on June 16, 2009. The plan indicates that the proposed geothermal project can be available for commercial operation by the end of 2016. For the purpose of this study, Black & Veatch assumed that the first proposed 50 MW geothermal generating units will be available for commercial operations starting in 2016.

Figure 10-10
Estimated Mount Spurr Project Development Plan
(Source: Ormat)



10.4.4 Wind Project Options

Alaska has abundant wind resources suitable for power development. Much of the best wind sites are located in the western and coastal portions of the State. The wind in these regions tends to be associated with strong high and low pressure systems and related storm tracks. Wind power technologies being used or planned in Alaska range from small wind chargers at off-grid homes or remote camps, to medium-sized machines displacing diesel fuel in isolated village wind-diesel hybrid systems, to large turbines greater than 1 MW. Alaska appears to also have significant potential for off-shore wind projects. Since off-shore wind projects are generally more expensive than on-shore projects, off-shore projects are not explicitly considered in this study.

In the Railbelt, several of the utilities are examining wind power projects, including:

- BQ Energy/Nikiski – 15 MW, HEA
- Fire Island – 54 MW, Chugach
- Eva Creek – 24 MW, GVEA
- Delta Junction – 50 MW, GVEA
- Arctic Valley – 25 MW, Chugach
- Bird Point – 10 MW, Chugach
- Alaska Environmental Power – 15 MW, GVEA
- 63 Other Projects in AEA’s Data Base

In addition, the developers of several proposed wind projects in the Railbelt have applied for grant requests from the AEA Renewable Energy Fund Grant Program, which was established by Alaska Legislature in 2008. Table 10-19 shows each proposed wind project’s name, applicant, estimated project cost, grant requested, and funding decision and amount recommended by AEA after two rounds of ranking and funding allocations conducted by AEA.

Table 10-19
AEA Recommended Funding Decisions - Wind

Project Name	Applicant	Project Cost ($000)	Grant Requested ($000)	Recommended Funding Decision	Recommended Funding Amount ($000)
Nikiski Wind Farm	Kenai Winds, LLC	$46,800	$11,700	Partial funding	$80
Kenai Winds	Kenai Winds, LLC	$21,000	$5,850	Partial funding	$2,000
AVTEC Wind	Alaska Vocational Technical Center	$709	$635	Not recommended(1)	None
Delta Wind	Alaska Wind Power, LLC	$135,300	$13,000	Not recommended(1)	None
Note: 1. The project did not pass Stage 2 review or was excluded in Stage 3 review for geographical spreading.					

Black & Veatch studied the details of each proposed wind project and applied the following screening criteria to determine which developments could be considered as a potential supply-side alternative in this RIRP study:

- Project size: Larger than 5 MW
- Permitting: In place or in progress
- Power Purchase Agreements (PPA): In place or in progress
- Readiness: Prepared for construction by end of 2010

Based on the review of the above information, Black & Veatch assumed that the proposed Fire Island project and the proposed BQ Energy/Nikiski project be considered as potential supply-side alternatives in this RIRP study. The following subsections discuss further details of these proposed projects.

10.4.4.1 Fire Island

Description of Project

A joint venture (JV) of CIRI, an Alaska Native Corporation, and enXco Development Corporation (enXco) has approached AEA for the potential development of a wind generation project on Fire Island, which is located in Cook Inlet approximately three miles off Point Campbell in Anchorage, Alaska. On May 14, 2009, the JV made a presentation to AEA to provide AEA staff with the latest status update of the proposed Fire Island Project. According to the JV, there is the potential to develop a wind generation plant with an estimated maximum output of 54 MW on Fire Island. Figure 10-11 illustrates a visual simulation of the proposed Fire Island wind generation project.

Figure 10-11
Visual Simulation of Fire Island Wind Generation Project
(Source: CIRI/enXco Joint Venture)

Figure 10-12 illustrates a preliminary site arrangement and interconnection route of the proposed wind project. The project will be based on installation of up to 36 GE 1.5 MW wind turbines. Each wind turbine will be equipped with reactive power and voltage support capabilities. The project is planned to be interconnected via 34.5 kV underground and submarine cables from an on-site 34.5 kV collector substation to Chugach's Raspberry substation. In addition, it is expected that the project will require the construction of a 5,000 square foot maintenance facility, approximately nine miles of gravel roads, and on-island housing facility for five maintenance staff.

For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be developed as a 54 MW nameplate-rated project.

Mode of Operation
It is expected that the wind generation project will be designed and permitted for intermittent operations subject to wind resource availability at the project site.

Capital Costs
EnXco provided estimated installed capital cost of $3,100/kW including interconnection costs. Since providing the cost estimate, enXco has closed their Anchorage office and Black & Veatch has been unable to confirm if the $3,100/kW capital cost included benefits of the American Recovery and Reinvestment Act of 2009. In 2008 the Alaska Legislature appropriated $25 million for the construction of the proposed underground and submarine cable project to interconnect the proposed wind generation project to the Railbelt grid.

Figure 10-12
Preliminary Site Arrangement and Interconnection Route
(Source: CIRI/enXco Joint Venture)

O&M Costs
O&M costs include fixed and variable costs.

Fixed O&M Costs
Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. Black & Veatch assumed $122/kW-yr in $2009 for fixed O&M costs.

Variable O&M
Variable O&M costs include consumables, lubricants, and major inspections of the wind turbine generators and associated equipment. Variable O&M costs vary as a function of plant generation. AEA provided and estimate of $9.75/MWh in 2008 dollars for variable O&M costs for Fire Island. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $10.00/MWh in 2009 dollars.

Capacity Factor
According the JV's May 14, 2009 presentation, the proposed wind generation plant will be able to achieve approximately 33 percent average capacity factor during its operating years.

Schedule
It is Black & Veatch understanding the proposed wind generation project has completed the following activities:

- Reached consensus to interconnect the project with Chugach at 34.5 kV level in the June 2008 meeting with Chugach, ML&P, HEA, and GVEA.
- Received proposals and met with potential construction contractors.
- Submitted draft power purchase agreements (PPAs) to Chugach, ML&P, HEA, and GVEA.

- Initiated integration studies.
- Received the U.S. Army Corps of Engineers permit approval for the proposed wind generation and related electricity transmission infrastructure project.

According the JV's May 14, 2009 presentation, the JV expects to begin site preparation work in 2009, complete the project design and site preparation in 2010, and begin erection of wind turbines in 2011. For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be available for commercial operations starting in 2012.

10.4.4.2 BQ Energy/Nikiski

Description of Project
The project, being developed by Kenai Winds LLC, is a 15 MW wind energy generation facility to be located in the Nikiski Industrial Area, in Nikiski, on the Kenai Peninsula, close to the Tesoro Refinery (Figure 10-13).

There is very little supporting infrastructure required. Kenai Winds does not require new power lines (other than local collection system) and does not require new roads, ports, nor aircraft access facilities.

There are several possible points of delivery in the area of the wind farm. The optimum location among those choices has not been selected, but HEA has agreed to purchase the full output of the Kenai Winds project.

The developer applied for a grant from the AEA Renewable Energy Fund Grant Program and was approved, during Round 1, funding for $80,000 to complete development activities.

On March 6, 2009 the developer submitted Supplemental Information to its previous Request for Grant Application to provide AEA staff with the latest status update of the proposed BQ Energy/Nikiski project. Details of the information contained in this document will be presented in the following subsections.

Figure 10-13
Kenai Peninsula, Nikiski
(Source: Kenai Winds LLC)

Mode of Operation
It is expected that the wind generation project will be designed and permitted for intermittent operations subject to wind resource availability at the project site.

Capital Costs
Capital costs are estimated to be $1,933/kW in 2009$ with limited supporting infrastructure required.

O&M Costs
O&M costs include fixed and variable costs. O&M costs of $0.023/kWh in 2009 dollars based on AEA's analysis of non-rural projects.

Capacity Factor
According to the March 6, 2009 document presented by Kenai Winds to AEA, preliminary review of the meteorological data available yields that the net capacity factor from the project is expected to be 28 percent.

Schedule
It is Black & Veatch understanding the proposed wind generation project has completed the following activities:

- Received the US Federal Aviation Administration permit approval for the proposed wind generation.
- Reached consensus to interconnect the project with HEA.
- Submitted draft power sales term sheet to HEA and discussions around those terms are underway.
- Initiated Interconnection Requirements Studies (IRS).

According to the Kenai Wind's document dated March 6, 2009, the developer is expecting to complete the project design and start site preparation by August 2009, and begin erection of wind turbines in November 2009. For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be available for commercial operations starting in 2010.

10.4.5 Modular Nuclear Project Option

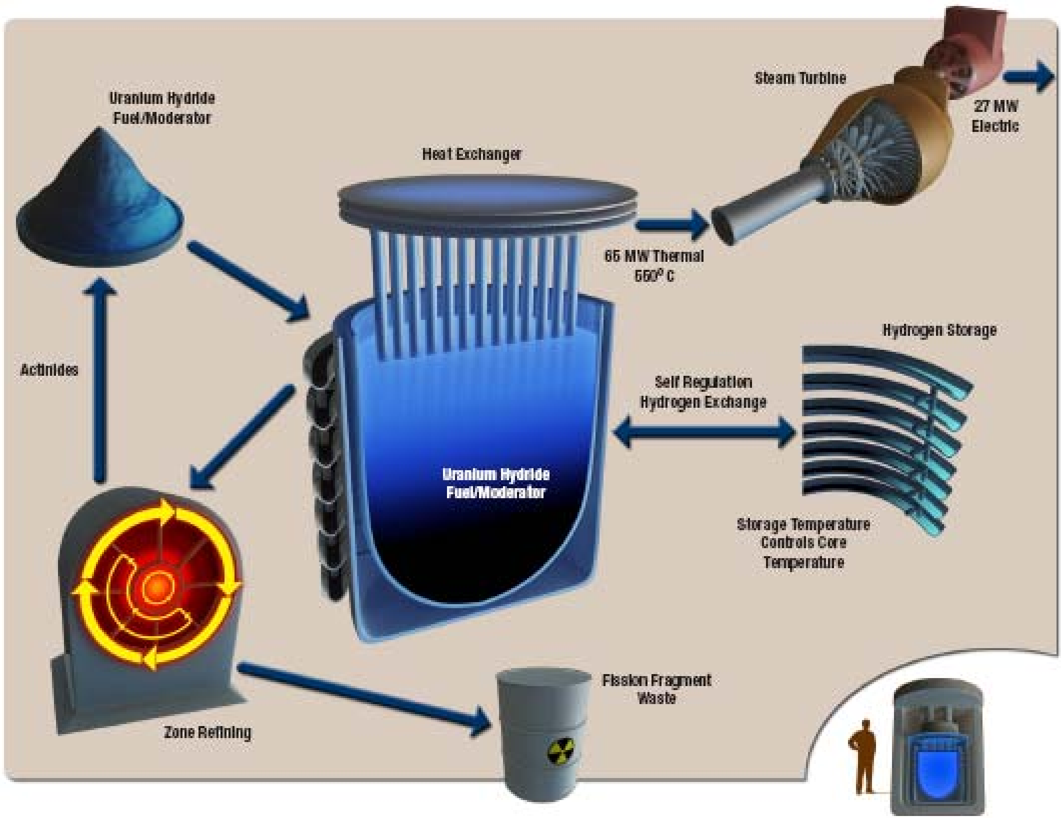
Description of Project
Alutiiq has been marketing a new small, modular nuclear power plant. This alternative would be available for use at most sites. Alutiiq has approached Chugach for a specific application of repowering at the Beluga power plant site.

The proposed nuclear project option is based on an advanced reactor design from Hyperion Power Generation (Hyperion) and Los Alamos National Laboratory. The project will consist of the following major components:

- A single unit, self-regulating, reactor module with heat exchanger.
- A uranium hydride fuel/moderator system.
- A steam turbine generator.
- Balance of plant mechanical, electrical, chemical, water, and interconnection systems.

Figure 10-14 illustrates a simplified power cycle process of the proposed nuclear project. The reactor will be designed to operate at an optimum temperature of 550°C and produce approximately 68 MW of thermal output. The thermal output from the reactor will be converted to approximately 27 MW of electrical output through a steam turbine generator.

Figure 10-14
Simplified Hyperion Power Cycle Diagram
(Source: Hyperion Power Generation)



Mode of Operation

It is expected that the project will be designed and permitted for both load following and base load operations.

Fuel Supply

Although it is anticipated that the reactor design for this project can accommodate a variety of fuel compositions, the initial reactor design and calculations were based on the use of uranium hydride. Depending on its use and mode of operations, each reactor is expected to last 7 to 10 years. The design proposed for this project does not allow for in-field refueling of the reactor. Each reactor will be sealed at the factory and transported to the project site for initial installation. When refueling is required after the anticipated 7- to 10-year period, a new reactor will need to be installed and the used reactor will need to be removed and transported back to the Hyperion factory for refurbishing and refueling.

For the purpose of economic evaluation for this study, Black & Veatch assumed that the project will incur zero variable fuel cost. However, Black & Veatch assumed that the project's reactor will be replaced every seven years. It is assumed that the reactor replacement cost will be approximately $25.0 million in 2008 dollars.

Capital Costs

Generic Greenfield Capital Costs
According to Hyperion's June 2008 "Brief for Public" presentation, General Atomics estimated that the construction cost for a 27 MW electrical output generic greenfield project will be approximately $37.0 million in 2008 dollars. Black & Veatch assumes that this cost includes engineering, procurement, and construction costs for equipment, materials, construction contracts, and other indirect costs. Black & Veatch assumes that owner's cost items such as land, contingency, etc., will be approximately $8.0 million in 2008 dollars, or 22 percent of the project construction cost. Therefore, it is anticipated that the total capital cost for the generic greenfield project will be approximately $45.0 million in 2008 dollars or approximately $1,667/kW.

Additional costs estimates provided by Chugach for small nuclear units include a 10 MW facility for $200 million or $20,000/kW and a 50 MW facility for $300 million or $6,000/kW. For evaluation purposes, Hyperion's cost estimates will be used in this study, but based on the other estimates, they appear to have the potential to be low.

Specific Chugach Repowering Capital Costs
Alutiiq provided a confidential rough cost for a Hyperion unit for repowering Beluga. Black & Veatch estimated the cost to connect the Hyperion unit to the Beluga steam turbine as well as an estimate of owner's cost. The total estimate cost of repowering the Beluga steam turbine is $39.6 million in 2009 dollars.

Non-fuel O&M Cost
Non-fuel O&M costs include fixed and variable costs.

Non-fuel Fixed O&M Costs
Non-fuel fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. It is assumed that the project will have a full-time plant staff of 15 personnel consisting of a plant manager, an administrative staff, a nuclear safety officer, and 12 O&M personnel. Therefore, for the purpose of this study the non-fuel fixed O&M costs associated with the project are estimated to be $2.6 million per year in 2009 dollars.

Non-fuel Variable O&M Costs
Non-fuel variable O&M costs include consumables, chemicals, lubricants, water, major inspections, and overhauls of the steam turbine generator and associated equipment. Non-fuel variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $2.56/MWh in 2009 dollars.

Availability Factor
Availability factor is a measure of the availability of a generating unit to produce power considering operational limitations such as unexpected equipment failures, repairs, routine maintenance, and scheduled maintenance activities. For the purpose of this study, Black & Veatch assumed that the average availability factor of this proposed nuclear plant will be 90 percent.

Schedule

According to the February 20, 2008 “Periodic Briefings on New Reactors” transcript and presentation Black & Veatch obtained from the Nuclear Regulatory Commission (NRC) website, Hyperion had submitted a letter of intent to NRC and met with the NRC in May 2007 to discuss the NRC licensing process. At the May 2007 meeting, Hyperion stated to NRC that Hyperion intended to submit a design certification application to the NRC in early 2012 as part of Hyperion’s plan to obtain a manufacturing license from NRC. A schedule (See Figure 10-15) illustrating the requested application timelines based on NRC receipt of letters of intent from all potential advanced reactor license applicants was presented by NRC during the February 20, 2008 briefing. The schedule shows that the Hyperion manufacturing license review process will be completed by the end of 2015 based on the assumption that the NRC will have appropriate staffing level and capability to review licensing applications submitted by all applicants.

Figure 10-15
Requested Potential Advanced Reactor Licensing Application Timelines
(Source: NRC February 20, 2008 Briefing Presentation Slide)

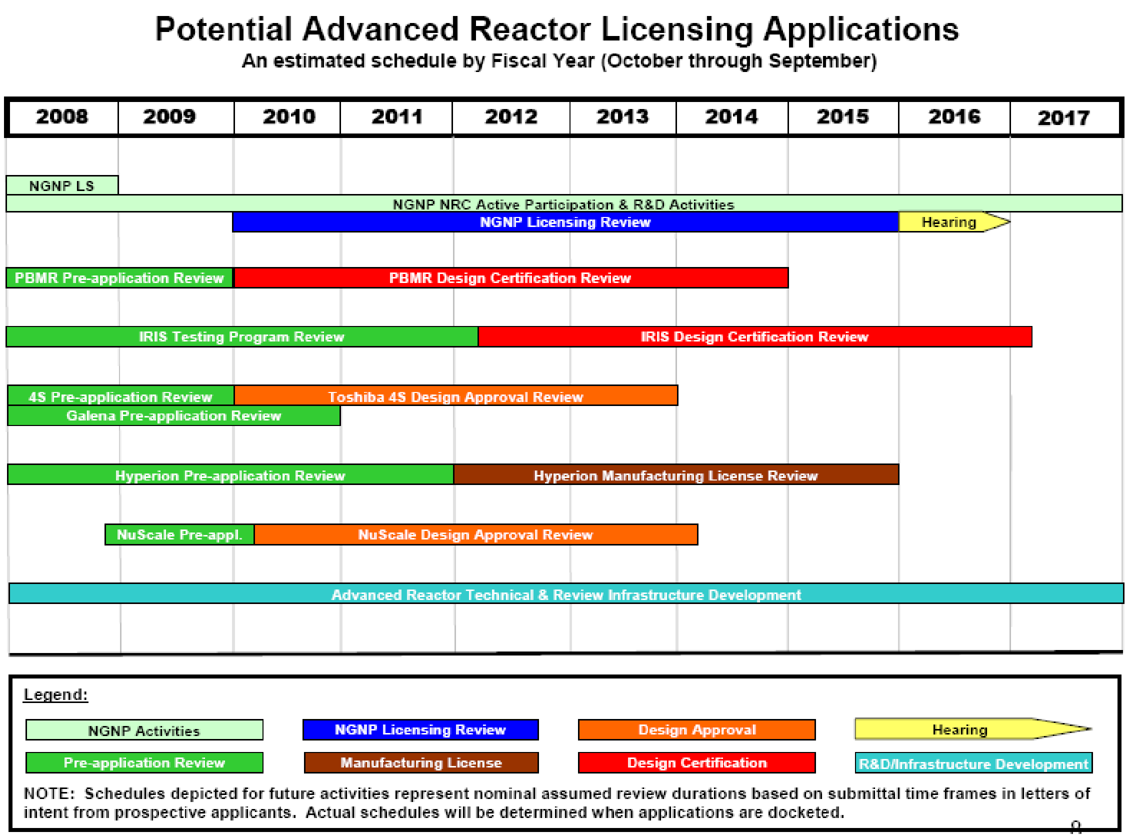
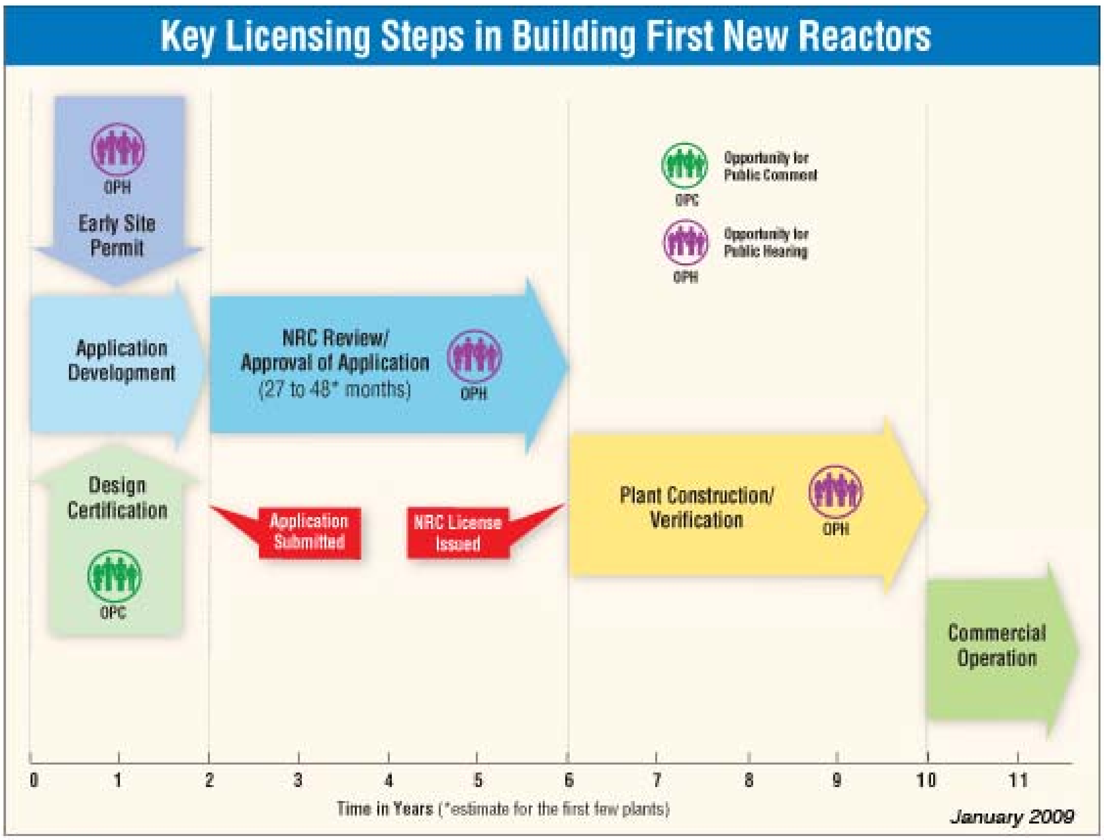


Figure 10-16 illustrates the Nuclear Energy Institute (NEI) latest understanding of the NRC's new licensing process. Figure 10-16 indicates that the expected time frame to process a Combined Construction and Operation License Application (COLA) is 27 to 48 months. Assuming that Hyperion proceeds in parallel, the license should be issued coincident with the Manufacturing License. Based on information provided by Hyperion, engineering, prototype, and testing will take four years. Further, it was assumed that it will take three years to manufacture and install the unit from issuance of the license to manufacture. Thus, the first of the units will be available for commercial operation in 2020.

Figure 10-16
NRC New Licensing Process and Construction Timelines for New Reactors
(Source: NEI website)



The NRC's new licensing process offers multiple opportunities for public input.

10.4.6 Municipal Solid Waste Project Options

Generic municipal solid waste projects were considered for the Anchorage and Interior areas. Black & Veatch sized the projects based on an estimated amount of trash produced in each area on a tons per day basis. This estimate was developed by multiplying the number of residents in each area by an estimated average of 4.5 pounds of trash per day, per person. The resulting tons per day number was compared with a list of municipal solid waste projects proposed and operating in the US to identify project sizes with similar tons per day consumption. As a result, 22 MW and 4 MW project capacities were developed for Anchorage and the Interior, respectively.

Black & Veatch assumed that the municipal solid waste projects would charge fees for taking the trash at a similar tipping fee rate currently charged by local landfills. Black & Veatch estimated capital costs of both projects to be $5,750/kW in 2009 dollars.

It should be noted that previous studies have been conducted regarding the feasibility of municipal solid waste projects in the Railbelt region. Furthermore, while Black & Veatch did not specifically evaluate landfill gas to energy technologies, they warrant further consideration.

10.4.7 Central Heat and Power

Central heat and power projects have not been explicitly modeled in this study. These projects are often developed by IPPs. If these projects meet the efficiency requirements to be certified as a Qualifying Facility (QF), then the existing utilities can be required to purchase the power from a central heat and power project at avoided costs. Since the qualification is very site specific, the development of specific projects to evaluate is beyond the scope of this study. It should be noted that under the GRETC concept, standard purchase power agreements will be available. The use of standard purchase power agreements will eliminate the specific need to be a FERC Qualifying Facility.

11.0 DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY RESOURCES

11.1 Introduction

The purpose of this section is to summarize Black & Veatch's approach to the assessment of DSM/EE measures as part of the overall RIRP project. A very important element of any comprehensive integrated resource plan is the development of a portfolio of proposed energy efficiency and demand reduction programs that can contribute energy savings and winter peak load reductions, and then evaluate these potential programs relative to alternative supply-side electric generation options on a cost per kWh and per kW basis. Those demand-side resources that prove to be more cost-effective than supply alternatives are then typically included in integrated resource planning model or models (in this case, Strategist® and PROMOD®) as a reduction to the load forecast. The resulting lower forecast then serves as the basis from which the alternative supply-side options are considered for adding generation resources when and as needed.

Black & Veatch has conducted a review of the Railbelt utilities' existing DSM/EE programs and developed a portfolio of potential DSM/EE measures for evaluation against supply-side alternatives. The costs and benefits associated with the DSM/EE measures are taken from existing data sources as described later in this section. Data on non-weather sensitive measures (e.g., lighting, appliances) are directly transferred from existing nationally-known sources, and data on weather-sensitive measures are transferred from existing sources using a regression model that considers both heating and cooling degree days as an adjustment factor. This approach has been used successfully in various other jurisdictions and has received general regulatory acceptance.

The design of DSM/EE programs involves three basic elements: 1) identification of target customer segments and end uses with the capacity to reduce energy use, 2) identification of technologies and behaviors that will result in the desired changes in consumption and load shape, and 3) identification of marketing approaches or program concepts to achieve the desired behavioral changes.

The short time frame, budget and limited data availability for this study precluded a rigorous analysis of electric DSM/EE potential (i.e., technical potential and maximum achievable potential) in the Railbelt region. However, Black & Veatch has made maximum use of existing data, augmented by interviews with a number of individuals, and employed industry-accepted data sources and analytical tools to produce a preliminary estimate of the cost-effective DSM/EE resources that exist within the Railbelt region.

In the next subsection, we present some background information on the Railbelt utilities' current DSM/EE programs and the literature sources that we reviewed. We then present a summary and characterization of the customer base for energy efficiency and demand reduction by company and sector. An estimate of DSM/EE potential is presented in the next subsection, followed by a discussion of the DSM/EE technologies or measures considered, screened, and included in the RIRP modeling. We conclude with some comments regarding the delivery of DSM/EE programs.

11.2 Background and Overview

11.2.1 Current Railbelt Utility DSM/EE Programs

Black & Veatch conducted two investigations to assess the current level of energy efficiency program activity at the Railbelt utilities. First, inquiries were made to the six Railbelt utilities and, second, websites of the utilities were researched.

Based upon the information gathered, Table 11-1 summarizes the current DSM/EE programs and related information offered by the Railbelt utilities.

Table 11-1
Current Railbelt Electric Utility DSM/EE-Related Activities

Utility	DSM/EE Programs and Other Assistance/Information Offered
Chugach	**Residential** • Provides compact fluorescent light (CFL) bulb coupons. **Other Assistance/Information** • Refers to a 2008 Board of Directors policy to establish an energy efficiency and conservation program. • Provides a calendar of events, workshops (sponsored by AHFC) and other activities (e.g. tours, fairs, contests, etc.) with links to the specific events. • Provides tips for buying and using appliances, CO_2 detectors, heating and cooling, holiday lighting, insulation, lighting, water heating, and windows. • Provides a tool to analyze accounts, which includes a table of costs for typical appliance usage and a link to the Energy Star® webpage's home energy yardstick which is a tool to analyze energy usage. • Provides a variety of documents related to energy efficiency.
GVEA	**Residential** • **Home$ense**: $40 energy audit that includes energy saving tips and installation of energy efficient products at no additional cost. **Commercial** • **Builder$ense**: rebate program for home builders who install electrical energy efficiency measures during construction. • **Business$ense**: rebate program of up to $20,000 for commercial members who reduce their lighting loads through energy efficient lighting retrofit projects. **Other Assistance/Information** • Link to AHFC and University of Alaska Fairbanks-Alaska Cooperative Extension Service, energy and housing. • Department of Energy document with tips and ideas on how to increase home energy efficiency and how to buy energy efficient products. • Calculator to determine savings by replacing standard incandescent light bulbs with compact fluorescents.

Table 11-1 (Continued)
Current Railbelt Electric Utility DSM/EE-Related Activities

Utility	DSM/EE Programs and Other Assistance/Information Offered
HEA	**Residential** • Information on WiseWatts program and incentives. • Offers a Black & Decker Power Monitor for $50. • Line of credit for HEA customers from $200 to $5,000 for the purchase of approved energy-efficient electrical appliances and other approved merchandise. The repayment period can be from 6 to 36 months upon approved credit. There is an application fee of $35 at the time the loan closes. **Other Assistance/Information** • Touchstone Energy Savers: contains links to Touchstone Energy® tools, tips and resources designed to create greater home comfort and promote energy efficiency. Included on this page are an on-line home energy saver audit, information about stimulus package energy efficiency and weatherization programs, and a link to Alaska Building Science Network. • Offers advice on how to select new energy efficient appliances and products for homes and businesses. Also provides appliance usage tips to reduce energy consumption. • Information on CFL and old refrigerator disposal in the area.
MEA	**Other Assistance/Information** • Provides information on the benefits of Energy Star® appliances, including a link to the EnergyGuide label. • Provides information on how to save energy by managing monitor and PC power. • Provides energy saving tips, including heating and cooling, home electronics, lighting, and new energy efficient homes. • Provides a link to Energy Star® Home Energy Yardstick, a tool to analyze your energy usage. • Provides links to the AHFC and Cold Climate Housing Research Center.
ML&P	**Commercial** • Sponsor of Green Star's Lighting Energy Efficiency Pledge (LEEP) which encourages businesses to upgrade and retrofit their lighting. Participating businesses receive technical support and resources to help them achieve energy savings and Green Star promotes participating businesses. **Other Assistance/Information** • Provides a link to Home Energy Saver, which is the Department of Energy's free home energy audit tool as part of the Energy Star® program. • Provides tips to reduce utility bills and provides links to the Municipality of Anchorage's low-income weatherization program and the AHFC Research Information Center.

11.2.2 Literature Review

As previously stated, the Railbelt utilities have limited experience in the implementation of DSM/EE programs; likewise, there is limited Alaska-specific information available typically required to complete an evaluation of the resource potential and cost-effectiveness of DSM/EE resources. To supplement the information available from the utilities, Black & Veatch relied on other Alaskan sources of information as shown in Table 11-2.

Table 11-2
DSM/EE-Related Literature Sources

Printed Materials Reviewed	Websites Reviewed
Alaska Energy Authority; *Alternative Energy and Energy Efficiency Assistance Plan July 1, 2007 to June 30, 2009*; 2009.	ACEP – Alaska Center for Energy and Power (University of Alaska); http://www.uaf.edu/acep/publications/detail/index.xml.
Alaska Energy Authority; *Alternative Energy & Energy Efficiency Update*; 2007.	Alaska Housing Corporation; http://www.ahfc.state.ak.us/home/index.cfm.
Alaska Energy Authority, et al.; *Village End-Use, Energy Efficiency Projects Phase II Results -2007-2008*; 2009.	Alaska Energy Authority; http://www.akenergyauthority.org/.
Chugach Electric Association; *End Use Model Results*; 1991. (provides residential and commercial end-use projections for Chugach, HEA, and MEA)	Cold Climate Housing Research Center (CCHRC); http://www.cchrc.org/default.aspx.
Information Insights, Inc.; *Alaska Energy Efficiency Program and Policy Recommendations*; 2008.	Denali Commission; http://www.denali.gov/index.php.
Information Insights, Inc.; *Alaska Energy Efficiency Program and Policy Recommendations – Appendices*; 2008.	Municipality of Anchorage, Alaska; http://www.muni.org/OECD/energyEfficiency.cfm.
	Renewable Energy Alaska Project (REAP); http://alaskarenewableenergy.org/tag/energy-efficiency/.

11.2.3 Characterization of the Customer Base

Table 11-3 provides a summary of the customer base for each of the six Railbelt utilities, including the total number of customers for each utility, as well as information on the numbers of customers in the largest population centers. This table also shows a breakdown of customers into residential, commercial and industrial sectors.

This information was used in the analysis of potential penetration rates for various DSM/EE measures as discussed later.

Table 11-3
Railbelt Electric Utility Customer Base

Alaska Railbelt Utilities		Total Cust.	Number of Population Centers	Major Population Center(s)	Pop.	Res. Cust.	Comm. Cust.	Ind. Cust.	Number of Schools in all Pop. Centers	Govt & Schools in city	Low Income Res in city
Golden Valley Electric Association	GVEA	42,866	29	Fairbanks	34,540	36,395	6,008	463	61	37	4,076
				North Pole	2,183					8	227
				Delta Junction	942					9	98
				Nenana	352					2	37
				Anderson	274					1	28
Matanuska Electric Association	MEA	53,503	20	Wasilla	9,780	49,939	3,564	0	49	27	1,017
				Palmer	7,804					13	812
				Houston	2,017					0	210
Chugach Electric Association & Anchorage Municipal Light and Power	CEA and ML&P	108,472	10	Anchorage	279,671	93,493	14,973	6	125	104	18,458
Homer Electric Association	HEA	27,401	22	Homer	5,691	23,811	3,563	27	29	10	592
				Soldotna	4,289					10	446
				Kenai	7,686						
				Kachemak City	443					0	46
				Seldovia	306					1	32
City of Seward Electric System	CES	2,567	1	Seward	3,061	1,973	476	118	4	4	318
TOTAL:		234,809	82		359,039	205,611	28,584	614	268	226	26,397

Organization	state	cities
Golden Valley Electric Association	5.6%	7.8%
Anchorage Municipal Light & Power	40.9%	57.2%
Matanuska Electric Association	2.9%	4.0%
Chugach Electric Association	0.0%	0.0%
Homer Electric Association	2.7%	3.8%
City of Seward Electric System	0.4%	0.6%
Total Pop in Railbelt	52.53%	73.42%

Sources:

Customer information	Energy Velocity by Ventix
Population data	http://www.census.gov/
Economic data:	http://www.census.gov/
Schools data:	http://www.eed.state.ak.us/Alaskan_Schools/Public/

11.3 DSM/EE Potential

The purpose of this subsection is to provide an overview of Black & Veatch's estimate of the potential for DSM/EE measures in the Railbelt region.

11.3.1 Methodology for Determining Technical Potential

The general approach for developing an estimate of the DSM/EE technical potential consisted primarily of the following three steps:

1. Black & Veatch reviewed the universe of measures that are available in the marketplace to increase energy efficiency. This review included not only the limited DSM/EE program experience in Alaska but also a review of the DSM/EE program experience of other utilities throughout the U.S.

2. Black & Veatch eliminated non-electric energy savings measures since this study is focused on meeting the demand and energy requirements of the electric utilities within the Railbelt region.

3. Black & Veatch conducted an intuitive, or qualitative, screening of potential DSM/EE measures based on certain criteria, which are discussed below.

11.3.2 Intuitive Screening

A universe of DSM/EE measures exists that provide energy savings over standard products that serve the same end uses. The majority of these measures are well proven in terms of their impact on electric demand and energy requirements based upon the experience of utilities in other regions of the country. To cull this list, Black & Veatch used a process to screen measures to identify those that are most appropriate for the Railbelt region. The primary objective of this effort was to select the most appropriate measures for further analysis.

There is a considerable range of new products and technology options that are available for energy efficiency and demand reduction applications. Many of these are available today to consumers in the Railbelt region, while others are less prevalent or readily available. Black & Veatch examined a broad array of the most relevant technologies and measures for residential and commercial (non-residential) applications, and considered the extent to which each technology and measure makes sense for the Railbelt region.

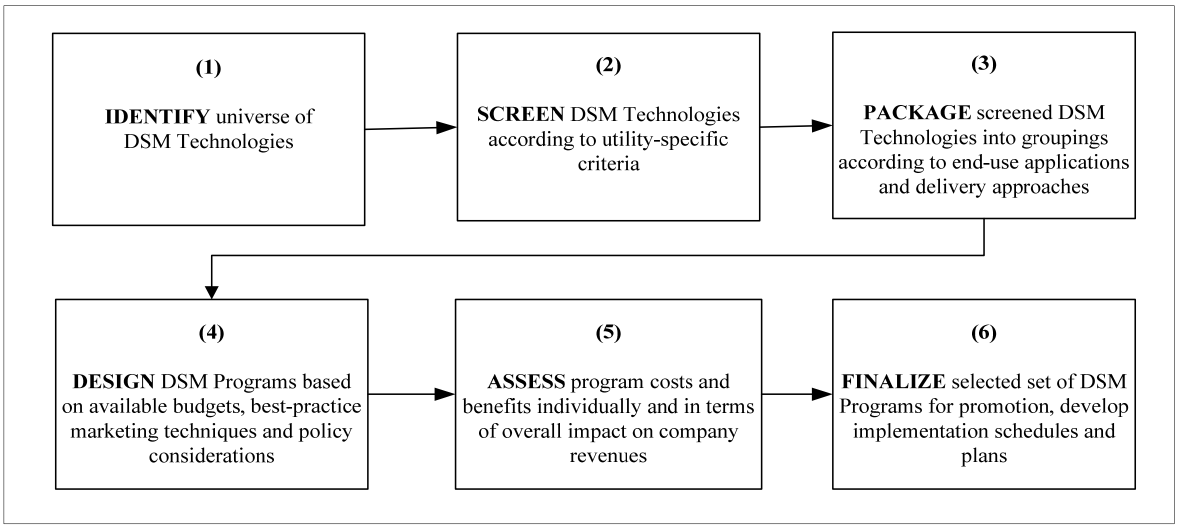
To ascertain which electric end-use measures would best provide energy efficiency opportunities for Railbelt electric customers, as well as help the Railbelt utilities meet their long-term energy and capacity planning goals, Black & Veatch felt that the initial step to aid in sifting through the number of measures would be to use an intuitive or qualitative technology screen. This process, first developed through the Electric Power Research Institute (EPRI) Customer Preference and Behavior Research Project in the 1980s, has been used by utilities across the nation as a first pass at the screening and ranking of DSM technologies.

Numerous measures were considered for the residential and commercial sectors. Certain criteria were developed to gauge the relative value of each measure for the Railbelt region, including: 1) the impact that each measure would have on the winter system load, 2) a preference for conservation measures (rather than peak impacting), and 3) whether the measure is currently offered in the marketplace. The Black & Veatch team felt that a review of each measure within these descriptive criteria would aid in indicating which measures "rise to the top" as "best" candidates and, as such, should be investigated for possible program inclusion.

11.3.3 Program Design Process

Once this initial screening was completed, Black & Veatch then grouped similar, or related, DSM/EE measures into potential DSM/EE programs that were further evaluated within the RIRP models. This approach is consistent with the approach typically used by utilities to develop DSM/EE programs, as shown on Figure 11-1.

Figure 11-1
Common DSM/EE Program Development Process



Typically, utilities develop detailed DSM/EE program plans for each program selected for implementation. These DSM/EE program plans commonly include the following elements:

- **Detailed description of the program--**Derived from best practices from various sources.
- **Reasons why the program would be successful in utility's service territory--**Derived from a comprehensive market assessment and background research.
- **Number of customers within the customer class/segment that are likely to adopt/use the proposed program--**Derived from market assessments and surveys, with a percent or modeled participation estimate based on experience from other utilities with similar programs; informed by actual results from other utilities offering similar programs.
- **Achievable energy savings--**From a variety of sources, consistent with a technology assessment and published reports.
- **Cost-effectiveness ratios/rating per individual program--**Calculated using standard tests, such as the Total Resource Cost (TRC), Participant, Administrators (or Utility) Cost, or Ratepayer Impact Measure (RIM) Tests, applying appropriate avoided cost figures.
- **Marketing plans which should include incentives, rebates and preferred distribution channels and how each reduces existing barriers to proposed program adoption/acceptance--**Based on best practices from a variety of sources; incentive amounts based on examples from other companies.
- **Detailed budget plans complete with explanations of anticipated increases/decreases in financial and human resources during the expected life of the program--**Based on best practices from a variety of sources, over a designated time period for the program life.

- **Recommended methodology or tracking tools for recording actual performance to budget--** Based on current standard practice using simple commercially available software.
- **Proposed program evaluations and reports--**Based on current standard practice using a logic model approach.

11.3.4 Achievable DSM Potential from Other Studies

There are several organizations that have estimated the potential for energy savings on a regional and statewide basis in recent years; most notably EPRI and the Edison Electric Institute (EPRI/EEI), and the American Council for an Energy Efficient Economy (ACEEE). None of these studies, however, specifically and exclusively examined Alaska. However, one study by the Energy Efficiency Task Force of the Western Governor's Association (WGA) was conducted under the Clean and Diversified Energy Initiative and published in January 2006. The states included in the study were Alaska, Arizona, California, Colorado, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming. The study estimates achievable potential for three years (2010, 2015, and 2020) at 7, 14, and 20 percent, respectively.

Taking Ohio as an example of a state with relatively little prior DSM/EE program offerings, the ACEEE estimates a total achievable energy savings potential of 33 percent by 2025. Other higher end percentages are seen in Illinois (ACEEE 1998) with 43 percent achievable energy efficiency potential, and a regional study for the Southwest that rendered 33 percent energy savings potential. [1]

The EPRI/EEI Assessment looked at the amount of energy savings deemed to be achievable in each of three time periods by sector and end use. The top 10 end uses did not vary considerably by region, and are shown on Figure 11-2 for the Western Census Region, which includes Alaska.

The EPRI/EEI report also indicates a demand response potential of 88 MW based on a 2006 assessment for Alaska and Hawaii combined (note: there is no indication of whether this is from the summer or winter peak).

These studies all provide comparative "top down" estimates from which to gauge the reasonableness of the estimates that Black & Veatch has derived from a "bottom up" assessment of DSM/EE potential in the Railbelt region.

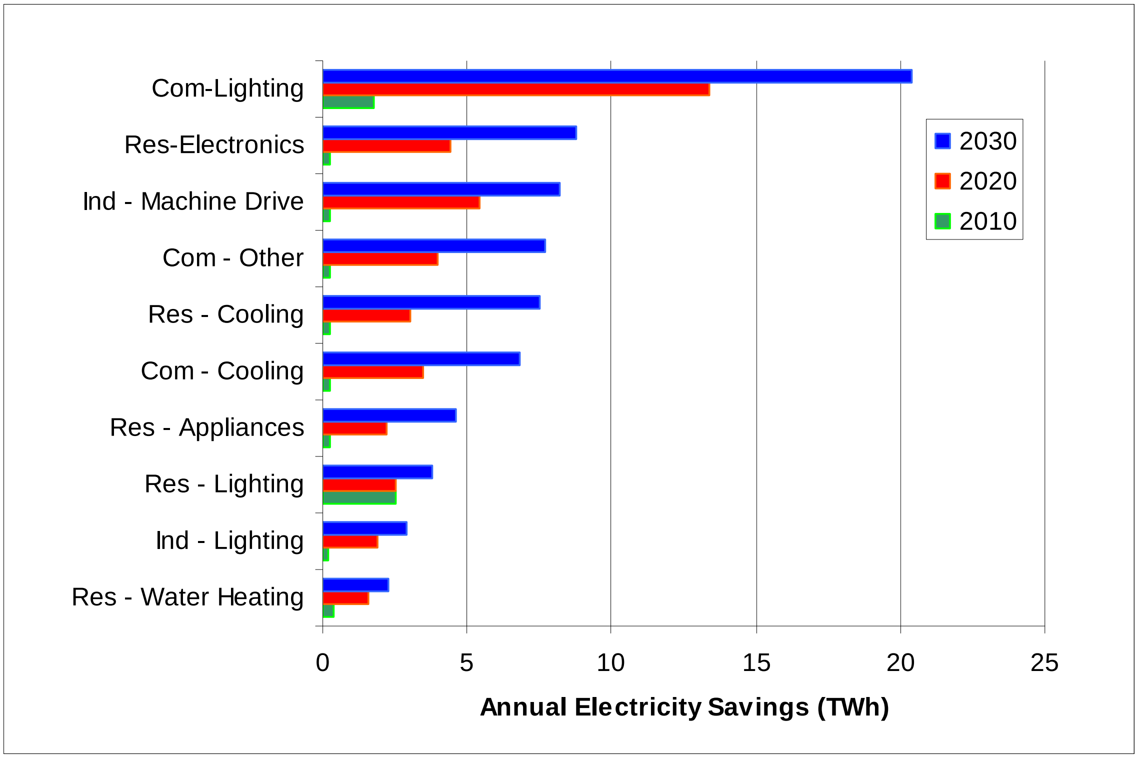
11.4 DSM/EE Measures

This section discusses the DSM/EE measures that are commonly considered in market potential studies of recent vintage. The standard approach to designing programs is to consider a wide range of measures, and then screen them by applying a set of criteria appropriate to the individual utility or region. The measures are then ranked and the most appropriate ones retained for modeling purposes.

Since there are numerous combinations of technology replacement situations (e.g., standard light bulbs with a 75 watt rating can be replaced with a compact fluorescent light bulb, CFL, using 15 watts; a standard 60 watt light bulb can be replaced with a 15 CFL, etc.), the modeling of measures only requires consideration of a representative group of measures in order to assess the potential benefits of promoting such measures in the region and service territory.

[1] US Department of Energy; *National Action Plan for Energy Efficiency*; Table A6-4 - Achievable Energy Efficiency Potential from Recent Studies; pages 6-16; July 2006.

Figure 11-2
EPRI/EEI Assessment: West Census Region Results



Black & Veatch began this phase of the work by considering a large number of residential and commercial/ industrial (C/I) measures. As previously discussed, two initial screens (i.e., removal on non-electric measures and intuitive screening) were applied to these lists.

This shorter list of electric-only measures was then reduced based on a set of four additional screening criteria as follows:

1. Relevance to the regional weather patterns
2. Commercial availability
3. Incremental cost per kWh over standard options
4. Contribution to winter peak load reduction

This review and ranking of the measures resulted in an abbreviated list of 21 residential and 51 C/I measures for further analysis. Table 11-4 summarizes this abbreviated list of residential and C/I measures that was selected for further analysis. It also provides the following information for each DSM/EE measure:

- Measure life
- Estimated kWh savings per customer
- Estimated kW savings per customer
- Incremental cost per installation

Table 11-4
Residential and Commercial DSM/EE Technologies Evaluated

Measure	Sector	Technology	Measure life	Estimated kWh percust	Estimated kW percust	Cost per installation ($2009)
Freezers Energy Star-Chest Freezer	Resid-NonWeather	Appliance	12	46.0	0.0	$ 50.88
Clothes Dryers	Resid-NonWeather	Appliance	14	144.0	0.0	$ 82.50
Refrigerators-Freezers Energy Star - Top Freezer	Resid-NonWeather	Appliance	12	79.0	0.0	$ 50.88
Refrigerators-Freezers Energy Star - Side by Side	Resid-NonWeather	Appliance	12	109.0	0.0	$ 50.88
Pump and Motor Single Speed	Resid-NonWeather	Appliance	10	694.0	0.4	$ 23.38
Smart Strip plug outlet	Resid-NonWeather	Appliance	5	184.0	0.0	$ 11.00
Freezer recycling	Resid-NonWeather	Appliance	6	1,551.0	0.2	$ 75.00
Refrigerator recycling	Resid-NonWeather	Appliance	6	1,672.0	0.2	$ 130.00
Heat Pump Water Heaters	Resid-NonWeather	Water Heater	15	2,885.0	0.3	$ 242.50
Low Flow Showerheads	Resid-NonWeather	Water Heater	12	518.0	0.1	$ 36.76
Pipe Wrap	Resid-NonWeather	Water Heater	6	257.0	0.0	$ 2.09
Holiday Lights	Resid-NonWeather	Lighting	10	10.6	0.0	$ 14.20
CFL fixtures	Resid-NonWeather	Lighting	12	78.0	0.0	$ 24.75
Torchiere Floor Lamps	Resid-NonWeather	Lighting	12	164.0	0.0	$ 10.00
LED Night Light	Resid-NonWeather	Lighting	12	22.0	0.0	$ 6.50
CFL bulbs regular - Outside	Resid-NonWeather	Lighting	9	191.6	0.0	$ 0.83
CFL bulbs regular	Resid-NonWeather	Lighting	9	44.1	0.0	$ 2.83
Ceiling Fans	Resid-Weather	Shell	15	47.8	0.0	$ 151.25
Duct sealing 20 leakage base	Resid-Weather	Shell	18	41.7	0.0	$ 143.70
Roof Insulation	Resid-Weather	Shell	20	41.7	0.0	$ 441.32
Setback thermostat - moderate setback	Resid-Weather	Cooling/Heating	9	152.1	0.0	$ 45.31
ENERGY STAR Steam Cookers 3 Pan	Comm-NonWeather	Water Heater	12	11,188.0	2.6	$ 1,141.25
Plug Load Occupancy Sensors Document Stations	Comm-NonWeather	Office Load	5	803.0	0.1	$ 50.88
HP Water Heater 10 to 50 MBH	Comm-NonWeather	Water Heater	15	21,156.0	4.2	$ 1,100.00
Motors 1 to 5 HP	Comm-NonWeather	Motor	15	113.3	0.024	$ 97.60
Motors 25 to 100 HP	Comm-NonWeather	Motor	15	1,056.0	0.224	$ 331.90
Motors 7.5 to 20 HP	Comm-NonWeather	Motor	15	408.4	0.087	$ 149.85
LED Exit Signs Electronic Fixtures (Retrofit Only)	Comm-NonWeather	Lighting	15	201.0	0.023	$ 33.00
LED Auto Traffic Signals	Comm-NonWeather	Lighting	6	275.0	0.085	$ 49.50
LED Pedestrian Signals	Comm-NonWeather	Lighting	8	150.0	0.044	$ 77.00
VFD HP 1.5 Process Pumping	Comm-NonWeather	Motor	15	1,623.4	0.343	$ 1,192.13
VFD HP 10 Process Pumping	Comm-NonWeather	Motor	15	10,713.4	2.286	$ 811.50
VFD HP 20 Process Pumping	Comm-NonWeather	Motor	15	21,643.1	4.571	$ 1,266.63
Vending Equipment Controller	Comm-NonWeather	Refrigeration	5	800.0	0.210	$ 78.76
Efficient Refrigeration Condenser	Comm-NonWeather	Refrigeration	15	120.0	0.118	$ 9.63
ENERGY STAR Commercial Solid Door Freezers less than 20ft3	Comm-NonWeather	Refrigeration	12	520.0	0.059	$ 41.25
ENERGY STAR Commercial Solid Door Freezers 20 to 48 ft3	Comm-NonWeather	Refrigeration	12	507.0	0.058	$ 330.00
ENERGY STAR Commercial Solid Door Refrigerators less than 20ft3	Comm-NonWeather	Refrigeration	12	905.0	0.103	$ 68.75
ENERGY STAR Commercial Solid Door Refrigerators 20 to 48 ft3	Comm-NonWeather	Refrigeration	12	1,069.0	0.122	$ 275.00
ENERGY STAR Ice Machines less than 500 lbs	Comm-NonWeather	Refrigeration	12	1,652.0	0.189	$ 330.00
ENERGY STAR Ice Machines 500 to 1000 lbs	Comm-NonWeather	Refrigeration	12	2,695.0	0.308	$ 825.00
ENERGY STAR Ice Machines more than 1000 lbs	Comm-NonWeather	Refrigeration	12	6,048.0	0.690	$ 550.00
Pumps HP 1.5	Comm-NonWeather	Motor	15	302.0	0.064	$ 313.75
Pumps HP 10	Comm-NonWeather	Motor	15	2,014.0	0.427	$ 116.30
Pre Rinse Sprayers	Comm-NonWeather	Water Heater	5	1,396.0	0.116	$ 9.63
Exterior HID replacement above 250W to 400W HID retrofit	Comm-NonWeather	Lighting	12	706.0	0.000	$ 585.20
High Bay 3L T5HO Replacing 250W HID	Comm-NonWeather	Lighting	12	449.0	0.103	$ 222.91
High Bay 4LT5HO Replacing 400W HID	Comm-NonWeather	Lighting	12	882.0	0.200	$ 159.28
High Bay 6L T5HO replacing 400W HID	Comm-NonWeather	Lighting	12	374.0	0.1	$ 369.27
High Bay Fluorescent 6LF32T8 Replacing 400W HID	Comm-NonWeather	Lighting	12	961.0	0.2	$ 70.84
High Bay Fluorescent 8LF32T8 Double fixture replace 1000W HID	Comm-NonWeather	Lighting	12	2,005.0	0.5	$ 136.84
CFL Fixture	Comm-NonWeather	Lighting	12	342.0	0.1	$ 21.70
CFL Screw in	Comm-NonWeather	Lighting	2	202.0	0.0	$ 8.29
Daylight Sensor controls	Comm-NonWeather	Lighting	12	14,800.0	3.8	$ 1,100.00
Central Lighting Control	Comm-NonWeather	Lighting	12	11,500.0	2.8	$ 2,035.00
Occupancy Sensors under 500 W	Comm-NonWeather	Lighting	10	397.0	0.1	$ 79.20
Low Watt T8 lamps	Comm-NonWeather	Lighting	12	15.0	0.0	$ 3.43
3 Lamp T5 replacing T12	Comm-NonWeather	Lighting	12	99.4	0.0	$ 110.09
4 Lamp T5HO replacing T12	Comm-NonWeather	Lighting	12	191.0	0.0	$ 168.33
HPT8 4ft 3 lamp, T12 to HPT8	Comm-NonWeather	Lighting	12	145.2	0.0	$ 75.99
HPT8 4ft 4 lamp, T12 to HPT8	Comm-NonWeather	Lighting	12	169.7	0.0	$ 80.88
T12HO 8ft 1 lamp retrofit to HPT8 T8 4ft 2 lamp	Comm-NonWeather	Lighting	12	174.0	0.0	$ 62.34
T12HO 8ft 2 lamp retrofit to HPT8 T8 4ft 4 lamp	Comm-NonWeather	Lighting	12	293.0	0.1	$ 80.88
T8 4ft 3 lamp	Comm-NonWeather	Lighting	12	128.8	0.0	$ 107.38
T8 4ft 4 lamp	Comm-NonWeather	Lighting	12	139.8	0.0	$ 113.90
T8 HO 8 ft 2 Lamp	Comm-NonWeather	Lighting	12	184.0	0.0	$ 124.92
Window Film	Comm-Weather	Cooling/Heating	10	256.0	0.1	$ 84.60
Refrigerant charging correction	Comm-Weather	Cooling/Heating	10	712.4	1.0	$ 21.10
VFD Fan	Comm-Weather	Cooling/Heating	10	1,185.6	0.0	$ 42.89
VFD Pump	Comm-Weather	Cooling/Heating	10	3,959.2	0.3	$ 41.01
Refrigeration Commissioning	Comm-NonWeather	Refrigeration	3	375.0	0.0	$ 37.29
Strip curtains for walk-ins - freezer	Comm-NonWeather	Refrigeration	4	613.0	0.1	$ 77.00

Tables 11-5 and 11-6 provide additional information regarding the input assumptions used in the evaluation of the residential and commercial DSM/EE measures, respectively. This information includes:

- Incremental equipment cost
- Rebate as a percentage of incremental equipment cost
- Rebate amount
- Administrative costs
- Vendor or other costs
- Total per unit costs

It should be noted that Black & Veatch did not complete a comprehensive cost-effectiveness evaluation of these measures using the traditional DSM cost-effectiveness tests (i.e., TRC, Participant, Utility and RIM tests). Regional avoided costs are required to evaluate DSM/EE measure using these tests, and these avoided costs were not available when this evaluation was completed as part of this project. Rather, Black & Veatch achieved the cost-effectiveness assessment of these measures by including them directly in the RIRP models, which allowed for a direct comparison of the economics of DSM/EE measures relative to alternative supply-side alternatives.

Furthermore, once the most appropriate technologies were screened, Black & Veatch estimated how many customers would adopt each technology each year in order to arrive at potential energy savings to be used in the RIRP modeling. Even though technologies are grouped into one or more program(s) for going to market, the application of a participation rate is done at the measure level. The number of customers available to adopt the technology was based upon the customer counts and appliance saturations discussed earlier. From this starting point, a set of technology adoption curves were applied that characterize the pattern of acceptance (or purchase) typical of products at different levels of marketing. For example, a high rebate amount for a product might be expected to achieve a high penetration in the early years, translating into a “steep” curve. On the other hand, a program that merely provides consumers with information about changing their behavior, but offers no monetary incentive, may result in an increase in related participation over time, but at a lower level and slower pace. To estimate maximum penetration rates for purposed of RIRP modeling, Black & Veatch used a series of technology adoption curves for DSM/EE studies from the BASS model. These curves are built from the original “S” shaped curve of product adoption and are a generally-accepted tool for characterizing consumer adoption patterns. Since Alaska is fairly new territory for DSM/EE programs, Black & Veatch assumed that the level of incentives required to move the market to adopt DSM/EE measures would average approximately 45 percent of incremental equipment costs.

Table 11-5
Input Assumptions - Residential DSM/EE Measures

Residential Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
Freezers Energy Star-Chest Freezer	$92.50	50%	$46.25	$4.63	--	$50.88
Clothes Dryers	$150.00	50%	$75.00	$7.50	--	$82.50
Refrigerators-Freezers Energy Star-Top Freezer	$92.50	50%	$46.25	$4.63	--	$50.88
Refrigerators-Freezers Energy Star-Side by Side	$92.50	50%	$46.25	$4.63	--	$50.88
Pump and Motor Single Speed	$85.00	25%	$21.25	$2.13	--	$23.38
Smart Strip Plug Outlet	$40.00	25%	$10.00	$1.00	--	$11.00
Freezer Recycling	$93.00	0%	--	--	$75.00	$75.00
Heat Pump Water Heaters	$700.00	25%	$175.00	$17.50	$50.00	$242.50
Refrigerator Recycling	$93.00	0%	--	--	$130.00	$130.00
Low Flow Showerheads	$31.60	100%	$31.60	$3.16	$2.00	$36.76
Pipe Wrap	$7.60	25%	$1.90	$0.19	--	$2.09
Holiday Lights	$12.00	100%	$12.00	$1.20	$1.00	$14.20
CFL Fixtures	$45.00	50%	$22.50	$2.25	--	$24.75
Torchiere Floor Lamps	$50.00	0%	--	--	$10.00	$10.00
LED Night Light	$5.00	100%	$5.00	$0.50	$1.00	$6.50
CFL Bulbs Regular-Outside	$3.00	25%	$0.75	$0.08	--	$0.83
CFL Bulbs Regular	$3.00	25%	$0.75	$0.08	$2.00	$2.83
Ceiling Fans	$275.00	50%	$137.50	$13.75	--	$151.25
Duct Sealing 20 Leakage Base	$215.82	50%	$107.91	$10.79	$25.00	$143.70
Roof Insulation	$756.95	50%	$378.48	$37.85	$25.00	$441.32
Setback Thermostat-Moderate Setback	$18.46	100%	$18.46	$1.85	$25.00	$45.31

Table 11-6
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
ENERGY STAR Steam Cookers 3 Pan	$4,150.00	25%	$1,037.50	$103.75	--	$1,141.25
Plug Load Occupancy Sensors Document Stations	$185.00	25%	$46.25	$4.63	--	$50.88
HP Water Heater 10 to 50 MBH	$4,000.00	25%	$1,000.00	$100.00	--	$1,100.00
Motors 1 to 5 HP	$88.00	75%	$66.00	$6.60	$25.00	$97.60
Motors 25 to 100 HP	$558.00	50%	$279.00	$27.90	$25.00	$331.90
Motors 7.5 to 20 HP	$227.00	50%	$113.50	$11.35	$25.00	$149.85
LED Exit Signs Electronic Fixtures (Retrofit Only)	$60.00	50%	$30.00	$3.00	--	$33.00
LED Auto Traffic Signals	$90.00	50%	$45.00	$4.50	--	$49.50
LED Pedestrian Signals	$140.00	50%	$70.00	$7.00	--	$77.00
VFD HP 1.5 Process Pumping	$1,445.00	75%	$1,083.75	$108.38	--	$1,192.13
VFD HP 10 Process Pumping	$2,860.00	25%	$715.00	$71.50	$25.00	$811.50
VFD HP 20 Process Pumping	$4,515.00	25%	$1,128.75	$112.88	$25.00	$,266.63
Vending Equipment Controller	$195.50	25%	$48.88	$4.89	$25.00	$78.76
Efficient Refrigeration Condenser	$35.00	25%	$8.75	$0.88	--	$9.63
ENERGY STAR Commercial Solid Door Freezers -Less Than 20ft3	$150.00	25%	$37.50	$3.75	--	$41.25
ENERGY STAR Commercial Solid Door Freezers-20 to 48 ft3	$400.00	75%	$300.00	$30.00	--	$330.00
ENERGY STAR Commercial Solid Door Refrigerators-Less Than 20ft3	$250.00	25%	$62.50	$6.25	--	$68.75
ENERGY STAR Commercial Solid Door Refrigerators-20 to 48 ft3	$500.00	50%	$250.00	$25.00	--	$275.00

Table 11-6 (Continued)
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
ENERGY STAR Ice Machines-Less Than 500 lbs	$600.00	50%	$300.00	$30.00	--	$330.00
ENERGY STAR Ice Machines-500 to 1,000 lbs	$1,500.00	50%	$750.00	$75.00	--	$825.00
ENERGY STAR Ice Machines-More Than 1,000 lbs	$2,000.00	25%	$500.00	$50.00	--	$550.00
Pumps HP 1.5	$350.00	75%	$262.50	$26.25	$25.00	$313.75
Pumps HP 10	$332.00	25%	$83.00	$8.30	$25.00	$116.30
Pre Rinse Sprayers	$35.00	25%	$8.75	$0.88	--	$9.63
Exterior HID Replacement Above 250W to 400W HID Retrofit	$1,064.00	50%	$532.00	$53.20	--	$585.20
High Bay 3L T5HO Replacing 250W HID	$277.60	73%	$202.65	$20.26	--	$222.91
High Bay 4LT5HO Replacing 400W HID	$289.60	50%	$144.80	$14.48	--	$159.28
High Bay 6L T5HO Replacing 400W HID	$447.60	75%	$335.70	$33.57	--	$369.27
High Bay Fluorescent 6LF32T8 Replacing 400W HID	$257.60	25%	$64.40	$6.44	--	$70.84
High Bay Fluorescent 8LF32T8 Double Fixture Replace 1,000W HID	$497.60	25%	$124.40	$12.44	--	$136.84
CFL Fixture	$78.92	25%	$19.73	$1.97	--	$21.70
CFL Screw-in	$30.14	25%	$7.53	$0.75	--	$8.29
Daylight Sensor Controls	$4,000.00	25%	$1,000.00	$100.00	--	$1,100.00
Central Lighting Control	$3,700.00	50%	$1,850.00	$185.00	--	$2,035.00
Occupancy Sensors-Under 500 W	$144.00	50%	$72.00	$7.20	--	$79.20
Low Watt T8 Lamps	$6.24	50%	$3.12	$0.31	--	$3.43
3 Lamp T5 Replacing T12	$200.16	50%	$100.08	$10.01	--	$110.09
4 Lamp T5HO Replacing T12	$306.06	50%	$153.03	$15.30	--	$168.33

Table 11-6 (Continued)
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
HPT8 4ft 3 Lamp, T12 to HPT8	$138.16	50%	$69.08	$6.91	--	$75.99
HPT8 4ft 4 Lamp, T12 to HPT8	$147.06	50%	$73.53	$7.35	--	$80.88
T12HO 8ft 1 Lamp Retrofit to HPT8 T8 4ft 2 Lamp	$113.35	50%	$56.68	$5.67	--	$62.34
T12HO 8ft 2 Lamp Retrofit to HPT8 T8 4ft 4 Lamp	$147.06	50%	$73.53	$7.35	--	$80.88
T8 4ft 3 Lamp	$130.16	75%	$97.62	$9.76	--	$107.38
T8 4ft 4 Lamp	$138.06	75%	$103.55	$10.35	--	$113.90
T8 HO 8 ft 2 Lamp	$151.42	75%	$113.57	$11.36	--	$124.92
Window Film	$153.81	50%	$76.91	$7.69	--	$84.60
Refrigerant Charging Correction	$38.36	50%	$19.18	$1.92	--	$21.10
VFD Fan	$155.96	25%	$38.99	$3.90	--	$42.89
VFD Pump	$149.14	25%	$37.28	$3.73	--	$41.01
Refrigeration Commissioning	$113.00	30%	$33.90	$3.39	--	$37.29
Strip Curtains for Walk-ins-Freezer	$200.00	35%	$70.00	$7.00	--	$77.00

11.5 DSM/EE Program Delivery

As will be discussed in Section 13, the RIRP models selected all DSM/EE measures for inclusion in each of the four alternative resource plans, based upon the costs incurred and savings achieved from the utility persepctive. The successful implementation of these resources, however, is dependent on several factors.

First, it is important that a comprehensive technical and achievable potential study be completed, including the comprehensive cost-effectiveness evaluation of the available DSM/EE measures and using Railbelt-specific information.

Second, it is Black & Veatch's belief that a regional entity should be formed to develop and deliver DSM/EE programs on a regional basis, in close coordination with the six Railbelt utilities. This entity could be the proposed GRETC organization or another entity focused exclusively on DSM/EE programs.

This was addressed in the REGA Study Final Report, which included the following observations regarding the potential deployment of DSM programs by the Alaska Railbelt utilities:

> *" …, the Railbelt utilities have limited experience with the planning, developing and delivering of DSM and energy efficiency programs. To date, the majority of efforts in the Railbelt region and the State as a whole have been focused on the implementation of home weatherization programs. These programs can significantly reduce the energy consumption within individual homes; however, given the limited saturation of electric space heating equipment and the general lack of air conditioning loads, the potential for DSM and energy programs are limited from the perspective of the Railbelt electric utilities.*
>
> *An implementation issue that needs to be addressed is whether the development and deployment of DSM and energy efficiency programs throughout the Railbelt region should be accomplished by the individual Railbelt utilities or whether a regional approach would result in more efficient and cost-effective deployment of these resources. Additionally, given the fact that the total monthly energy bills paid by residential and commercial customers in the Railbelt have increased significantly in recent years and given that natural gas is the predominant form of space heating within the majority of the Railbelt region, it may be appropriate for the electric utilities to work jointly with Enstar to develop DSM and energy efficiency programs that would be beneficial to both. This would create economies of scope for the region and reduces the delivery costs of DSM and energy efficiency programs." (pps. 49-50)*

Third, the Railbelt electric utilities should work closely with Enstar and the AHFC with regard to the implementation of DSM/EE programs.

These points are discussed further in Section 16.