Glossary [1]

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. Comprises three groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free basis:

Coal	**Fixed Carbon Limits**		**Volatile Matter**	
	GE	**LT**	**GT**	**LE**
Meta-Anthracite	98	-	-	2
Anthracite	92	98	2	8
Semianthracite	86	92	8	14

Ash: Impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on an :q.as received:eq. or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes.

Average Revenue per Kilowatthour: The average revenue per kilowatthour of electricity sold by sector (residential, commercial, industrial, or other) and geo graphic area (State, Census division, and national), is calculated by dividing the total monthly revenue by the corresponding total monthly sales for each sector and geographic area.

(1) Source: Energy Information Administration, U.S. Depart of energy, Electric Power Annual, 1997.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated through multiplication of the rate from the appropriate electric rate schedule by the level of consumption.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent. It is used for generating electricity, making coke, and space heating. Comprises five groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free (mmf) basis for fixed-carbon and volatile matter and a moist mmf basis for calorific value.

	Fixed Carbon Limits		**Volatile Matter Limits**		**Calorific Value Limits Btu/lb**	
	GE	**LT**	**GT**	**LT**	**GE**	**LE**
LV	78	86	14	22	-	-
MV	69	78	22	31	-	-
HVA	-	69	31	-	14000	-
HVB	-	-	-	-	13000	14000
HVC	-	-	-	-	10500	13000

LV = Low-volatile bituminous coal
MV = Medium-volatile bituminous coal
HVA = High-volatile A bituminous coal
HVB = High-volatile B bituminous coal
HVC = High-volatile C bituminous coal

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Capacity (Purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce, for the purpose of statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration from lignite to anthracite. Lignite contains approximately 9 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 to 28 million Btu per ton.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and :q.another form of useful thermal energy through the sequential use of energy,:eq. and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The sum of two or more peakloads that occur in the same time interval.

Coke (Petroleum): A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion factor is 5 barrels (42 U.S. gallons each) per short ton.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electric Plant (Physical): A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and / or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning(HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Facility: An existing or planned location or site at which prime movers, electric generators, and / or equipment for converting mechanical, chemical, and / or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type. For a cogenerator, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission (FPC) was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. The FPC was abolished on September 20, 1977, when the Department of Energy was created. The functions of the FPC were divided between the Department of Energy and the Federal Energy Regulatory Commission.

FERC: The Federal Energy Regulatory Commission.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particule matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Gas: A fuel burned under boilers and by internal combustion engines for electric generation. These include natural, manufactured and waste gas.

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peakload, or the load over a specified time period.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management. (Interruptible Load, as reported here, is synonymous with Inter ruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peakload effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peakload effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis

	Limits Btu/lb.	
	GE	**LT**
Lignite A	6300	8300
Lignite B	-	6300

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

Noncoincidental Peak Load: The sum of two or more peakloads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is :q.operable:eq. after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Percent Difference: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Profit: The income remaining after all business expenses are paid.

Public Authority Service to Public Authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State or Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Public Street and Highway Lighting: Public street and highway lighting includes electricity supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Part 292.

Railroad and Railway Services: Railroad and railway services include electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peakload for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenue: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Short Ton: A unit of weight equal to 2,000 pounds.

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source.

Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks: A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Sub bituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

APPENDIX 2

Comparison of Selected State Restructuring Legislation

Start Date of Retail Competition		
Nevada	A.B. 366; 7/16/97	Customers may begin obtaining generation, aggregation, and any other potentially competitive services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest. (Section 39, p. 12)
California	H.B. 1890; 8/31/96	3/31/98 (p. 30, 42)
Maine	H-568, (LD 1804); 5/23/97	Beginning on 3/1/00, all consumers have the right to purchase generation services from competitive providers. (p. 1)
Montana	S.B. 390; 5/2/97	On or before 7/1/98, customers with loads greater than 1000 kW must have opportunity to choose an electric supplier. Co-ops may file notice with PSC, within one year after effective date of Act, electing not to participate in retail access. (p. 4, 11)
New Hampshire	H.B. 1392; 5/21/97	PUC to implement in most expeditious manner and no later than 1/1/98. PUC may delay to 7/1/98 but not longer without legislative approval. (p. 9)
Oklahoma	S.B. 500; 4/25/97	All retail customers are permitted to choose their retail electric energy suppliers by 7/1/02. (p. 3-4)
Pennsylvania	H.B. 1509; 11/26/96	Transition period to begin on 1/1/97. All customers to have retail access by 1/1/01. (p. 39, 84)
Rhode Island	96-H8124 (Sub. B); 8/7/96	By 1/1/97 each distribution company shall file with PUC a plan for transferring ownership of generation, transmission, and distribution facilities into separate affiliates. Company shall implement plan within 3 months after retail access is available to 40 percent of kWh sales in New England. PUC may extend time if necessary. (p. 17-18)
Massachusetts	H.B. 5117	3/1/98 for all customers
Connecticut	H.B. 5005, 4/29/98	35% of each companies' peak load, consisting of customers in distressed municipalities will be able to choose their electric supplier by January 1, 2000. The remainder will be able to choose starting July 1, 2000.
Illinois	H.B. 362	10/99 All large industrial customers, 33% of nonresidential customers. 12/00 - remaining 66% of non-residentials. 5/02 - all residentials.

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Phase-in of Retail Competition		
Nevada	A.B. 366	PUC may establish different dates for different services and different geographic areas and authorize retail competition in gradual phases. Utilities shall submit to PUC plan for compliance with Act, including information PUC needs to: set rates (e.g., utilities' cost to provide service and estimate of required revenue), allocate costs of service among customers, and adopt regulations for potentially competitive services. PUC may exempt sellers from certain portions of Act if necessary to achieve effective competition. (Section 39, p. 12; Section 49, p. 20)
California	H.B. 1890	Full retail access for all customers no later than 1/1/02; phase-in to be equitable to all classes as determined by PUC. (p. 5, 42, 91)
Maine	H-568, (LD 1804)	Beginning 3/1/02, electric billing and metering services are subject to competition. The PUC may establish an earlier date except in no case may the date be prior to 3/1/00. (p. 3)
Montana	S.B. 390	Transition period begins 7/1/98 for customers with loads greater than 1000 kW; all customers eligible by 7/1/02, unless the PSC determines added time is needed because workable competition does not exist. Full implementation may not be delayed beyond 7/1/04, however, for customers with loads greater than 1000 kW and not beyond 7/1/06 for all other customers. Participating co-ops must adopt transition plans on or before 7/1/01, and the transition period may not extend beyond 7/1/02, although the transition plan may be altered under certain circumstances. (p. 3-5, 9, 12-13)
New Hampshire	H.B. 1392	On the effective date of the Act, PUC shall undertake a generic proceeding to develop a statewide industry restructuring plan in accordance witl the legislative principles in the bill. Final order is due by 2/28/97. PUC shall require all utilities to submit compliance filings. No utility shall be required, however, to commence implementation until filings representing 70 percent of retail sales have been implemented. (p. 9-10)
Oklahoma	S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative Task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. A defined period for transition shall be established. (p. 4)
Pennsylvania	H.B. 1509	As of 1/1/99, maximum of 33 percent of peak load in each customer class will have direct access; 66 percent by 1/1/00; 100 percent by 1/1/01. PUC may extend 1/1/99 implementation date for 6 months. PUC to conduct milestone reviews to ensure technically workable and equitable transition. (p. 35, 39-41)
Rhode Island	96-H 8124, Sub. B	On 7/1/97, distribution companies required to offer retail access from non-regulated power producers to all new commercial and industrial customers with anticipated annual demand of 200 kW or more, all existing manufacturing customers over 1500 kW, and all state accounts, not to exceed 10 percent of total kW sales. On 1/1/98 access to include all existing manufacturers over 200 kW and all towns in state, not to exceec 20 percent of total kW sales. Access for all customers within 3 months after access is available to 40 percent or more of the kW sales in all New England states, but not later than 7/1/98. PUC may extend final deadline up to 6 months. (p. 24-25)
Massachusetts	H.B.5117	No phase-in

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Phase-in of Retail Competition (cont.)		
Connecticut	H.B. 5005	(see above start date info)
Illinois	H.B. 362	(see above start date info)

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Pilot Program		
Nevada	A.B. 366	
California	H.B. 1890	
Maine	H-568, (LD 1804)	
Montana	S.B. 390	Beginning 7/1/98, utilities shall conduct pilot programs using samples of residential and small commercial customers. Utilities must file a report with the PSC and the transition advisory committee on or before 7/1/00 analyzing the results of the pilot programs. Co-ops may also establish pilot programs for customers with loads less than 1000 kW. (p. 3-4, 9)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	PUC has authority to require utilities to submit proposals for pilots to begin 4/1/97. Program must commit 5 percent of peak load for each customer class. Minimum period for pilot is 1 year and shall include an evaluation process as directed by PUC. (p. 42-45)
Rhode Island	96-H 8124, Sub. B	
Massachusetts	H.B. 5117	
Connecticut	H.B. 5005	
Illinois	H.B. 362	

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Primary Responsibility for Implementation of Retail Competition		
Nevada	A.B. 366	PUC shall promulgate regulations to implement Act and shall determine which electric services are potentially competitive. Such services are defined as ones that: will not harm one or more customer classes; will decrease cost; increase quality or innovation, where effective competition is likely to develop; will advance competitive position of state; and won't jeopardize safety or reliability. If PUC determines that market for potentially competitive service does not include effective competition, it shall establish method for determining prices, terms, and conditions of service. Effective competition means an individual seller can't significantly influence the price of service. (Sections 39-52, p. 12-22 Section 337, p. 149)
California	H.B. 1890	PUC. (p. 42)
Maine	H-568, (LD 1804)	PUC. PUC may impose by rule any additional requirements necessary to carry out the purposes of the Act, except PUC may not regulate the rates of competitive providers. (p. 5)
Montana	S.B. 390	All public utilities shall submit a transition plan to the PSC not later than 1 year before retail choice is offered. PSC shall develop a procedural schedule for considering transition plans and issue a final order within 9 months after the plan is filed. On approval of plan, PSC shall enforce the plan in its final order. PSC may extend the transition period if workable competition does not exist. Workable competition exists if competition is sufficient to inhibit monopoly pricing or anti-competitive price leadership. (p. 5, 12-13)
New Hampshire	H. 1392	PUC authorized to order such charges and other service provisions and to take such other actions substantially consistent with the legislative principles in the bill that are necessary to implement restructuring. (p. 3, 11)
Oklahoma	S.B. 500	Legislature directs Corporation Commission to study all relevant issues relating to restructuring and develop a proposed industry restructuring framework under the direction of the legislative task force. Commission shall address appropriate steps to achieve an orderly transition and may include, in addition to the directives in this Act, other provisions Commission deems necessary and appropriate. However, Commission is expressly prohibited from promulgating rules or orders relating to restructuring without prior express legislative authorization. (p. 4)
Pennsylvania	H.B. 1509	PUC. (p. 28-29)
Rhode Island	96-H 8124 Sub. B	PUC and the Division of Public Utilities and Carriers. (p. 2)
Massachusetts	H.B. 5117	Department of Telecommunications and Energy (DTE), Division of Energy Resources (DOER)
Connecticut	H.B. 5005	Department of Public Utility Control (DPUC)
Illinois	H.B. 362	Public Utility Commission

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Independent System Operator (ISO)		
Nevada	A.B. 366	
California	H.B. 1890	Control of transmission system given to ISO. Utilities cannot collect CTC unless they commit control of their transmission assets to ISO. ISO governed by Oversight Board selected by governor and legislature. (p. 30, 36-39, 87, 90)
Maine	H-568, (LD 1804)	The governance of any ISO with responsibility for operations of the regional transmission system must be fully independent of influence by market participants. The PUC shall use all means within its authority and resources to advocate for and promote the interests of Maine ratepayers in any FERC proceeding involving the development, governance, operations, or conduct of an ISO. PUC shall monitor events in the region pertaining to the development of an ISO, the management of competitive access to the regional transmission system, and rights to negotiate potential contracts between buyers and sellers. If the PUC determines that there is insufficient independence on the part of the ISO, the PUC shall provide a report to the joint standing committee of the legislature with recommendations to remedy the problem. (p. 20, 22-23)
Montana	S.B. 390	
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	All participants encouraged to coordinate plans and transactions through ISO or functional equivalent. ISO should, and PUC shall, set and enforce inspection, maintenance, and repair standards. (p. 23)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of ISO. (p. 22)
Massachusetts	H.B.5117	Established as of 3/1/98. Monitored and analyzed by DOER.
Connecticut	H.B. 5005	The licensing process for sellers of electricity begins April 1, 1999 and requires that the seller be registered with or certified by the regional ISO, ISO-New England, or have a contractual relationship with an entity that is so registered or certified. The seller must be in compliance with all ISO-New England rules and standards and must own or purchase such capacity and reserves as ISO-New England may require.
Illinois	H.B. 362	As of enactment of bill, each electric utility company will file a request to join an ISO. If by 3/31/99, FERC has not approved the ISO application; or if by 6/30/99, all utilities have not applied to be a part of the ISO, an Oversight Board will be formed to oversee creation of ISO.

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Power Pool		
Nevada	A.B. 366	
California	H.B. 1890	Power Exchange established to operate an efficient, competitive auction for electricity open to all suppliers on a nondiscriminatory basis.(p. 5, 39)
Maine	H-568, (LD 1804)	
Montana	S.B. 390	
New Hampshire	H.B. 1392	New England Power Pool should be reformed to compliment restructuring on a regional basis. Any pool structure should not preclude bilateral contracts and should not preclude ancillary pool services from being obtained from non-pool sources. (p. 8)
Oklahoma	S.B. 500	Legislative task force is authorized to retain consultants to study the benefits of establishing a Power Exchange which would operate as a powe pool allowing power producers to compete on common ground in the state. (p. 9)
Pennsylvania	H.B. 1509	PUC to take all necessary steps to encourage interstate power pools. PUC and utilities to work with federal and state governments, regional reliability councils, and interstate power pools to ensure reliable service. (p. 37)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit recommendations to legislature for changes to regional power pool that would facilitate creation of voluntary power exchange. PUC shall establish regulations for non-regulated power producers selling into state that are necessary t meet operating and reliability standards of regional power pool. (p. 22)
Massachusetts	H.B.5117	New England Power Pool should be used to provide strong coordination and enforceable protocols for all users of the power grid and to promote the use of the interconnected regional transmission systems.
Connecticut	H.B. 5005	(see text above for Massachusetts)
Illinois	H.B. 362	

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Mandatory Rate Reductions or Rate Caps		
Nevada	A.B. 366	Rates charged for residential services must not exceed the rate charged for the service on 7/1/97. The rate cap remains in effect until 2 years after the date the PUC repeals the regulations that established the pricing method for the service. The PUC may approve an increase in the rate for residential service in an amount that does not exceed the increase necessitated to ensure the recovery by the utility of just and reasonable costs. (Section 45, p. 18)
California	H.B. 1890	Small customers receive at least 10 percent reduction on 1/1/98 and no less than 20 percent by 4/1/02. Can be financed with rate reduction bonds. (p. 5, 28, 49)
Maine	H-568, (LD 1804)	When retail access begins, PUC shall ensure that standard-offer service is available to all consumers of electricity. By 2/15/98, PUC shall provisionally adopt rules establishing terms and conditions for standard-offer service. If qualifying bids for standard-offer service in any service territory, when combined with the regulated rates of transmission and distribution service and any stranded costs charge exceed, on average, the total rate for electricity immediately before the implementation of retail access, PUC shall investigate whether implementation of retail access remains in the public interest or whether other mechanisms to achieve the public interest and to adequately protect consumer interests need to be put in place. PUC shall notify legislature of results of its investigation and its determination. (p. 17-18)
Montana	S.B. 390	Rate moratorium during transition period: 7/1/98 thru 6/30/00, utilities may not charge more than rates in effect on 7/1/98; 7/1/00 thru 6/30/02, utilities may not increase the increment of rates normally allocated to electric supply-related costs above those associated with such costs in effect on 7/1/98. From 7/1/00, utilities may propose increases to rate increments normally allocated to T&D costs. Increased costs related to universal system benefit programs greater than those in effect on passage are exempt from rate caps, as are increased costs necessary to implement full customer choice including metering, billing, and technology. Certain other exemptions are allowed in extraordinary cases. (p. 6-8)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	Rates capped at 1/1/97 levels for 54 months or until stranded costs are recovered and all customers have retail access, whichever is shorter. Additionally, generation component of rates is capped for 9 years or until distribution utility has collected stranded costs and all customers have direct access, whichever is shorter. (p. 30-31)
Rhode Island	96-H 8124 Sub. B	Within 3 months after retail access is available to 40 percent of the kW sales in New England and extending through 2009, distribution companies must arrange power contracts for their customers who have not contracted for their own power supply such that the average revenue per kWh received from the customer shall equal the price for the 12-month period ending 9/30/96, with certain inflationary adjustments. No customer who chooses this standard offer and subsequently contracts with their own supplier shall be required to pay an exit fee. (p. 26)
Massachusetts	H.B.5117	2.8 cent/kWh standard offer charge for generation offered by energy producers affiliated with established distribution companies. 10% rate reduction for all customers off rates in effect 8/97. Proceeds from securitization, if chosen and approved, can be used toward further reducing rates by additional 5%.
Connecticut	H.B. 5005	From 7/1/98 until 1/1/00, rates are capped at their 12/31/96 levels. Starting 1/1/00, each distribution company must provide service under a "standard offer" to those customers who do not arrange for service from an alternate supplier. The standard offer, provides for a 10% reduction (off rates effective 12/31/96). This requirement runs for 4 years. DPUC must adjust rates under the standard offer to reflect changes in taxes and fuel costs. Starting 1/4/04, distribution companies must procure power for consumers who do not obtain service from competitive suppliers, but can charge market rates for this power.
Illinois	H.B. 362	ComEd and IP residential rate reductions: 8/98 - 15%; 10/02 - 0%. Other suppliers except CILCO's residential rate reductions: 8/98 - 5% (2% CILCO); 5/02 - Max 5%, 10/02 - reflective of Midwest avg. (CILCO has had historically low rates compared to the Midwest avg, therefore, it doesn’t have to offer as substantial rate reductions as ComEd and IP. Non-residential customers get no rate reduction.)

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Financing Rate Reductions and Stranded Costs		
Nevada	A.B. 366	
California	H.B. 1890	Provides for rate reduction bonds to finance rate reductions and stranded ("transition") costs. (p. 5-6, 75-87)
Maine	H-568, (LD 1804)	
Montana	S.B. 390	PSC may authorize the imposition and collection of fixed transition amounts and the issuance of transition bonds. After 7/1/97, a utility may apply to the PSC for a determination that certain transition costs may be recovered through the issuance of transition bonds. If such bonds are not issued within 4 years of the PSC order, the order must terminate. A utility may apply for an extension or renewal of the order. Order must se forth the term over which transition bonds are to be paid—not to exceed 20 years. Upon issuance of transition bonds, the financing orders and fixed transition amounts must be irrevocable. Cost savings associated with and resulting from the bonds must benefit customers. Proceeds fron bonds must be used to recover, reimburse, finance or refinance transition costs, and to acquire transition property. Bonds may not constitute an indebtedness or loan of credit against the state or a political subdivision thereof. Co-ops may fully recover transition costs approved by local governing body. (p. 2-3, 6-7, 10,16-21)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	All transition costs shall be recovered by virtue of savings generated by increased efficiency in markets brought about by restructuring. All classes of consumers shall share in the transition costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring. Study shall include but is not limited to examination of IOU financing and any other financial issues Commission deems appropriate. Final report shall be provided to legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania	H.B. 1509	PUC may approve utility request for issuance of transition bonds for some or all of its stranded costs. If approved, the utility's rates or its CTC must be reduced by an amount equal to the revenue requirement of the stranded costs for which transition bonds have been issued. (p. 52-53, 69-84)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B.5117	As of 7/1/98, DTE will review purchase power contracts to determine if utility companies have made efforts to reduce or renegotiate them in order to reduce stranded costs. Non-mitigable stranded costs can be collected through a transition charge. Customers can only bypass transition charge if they have already notified utility company of intention to cogenerate. No exit fee would be charged that customer in that case.
Connecticut	H.B. 5005	Certain stranded costs resulting from generation-related regulatory assets and above-market long-term contracts are eligible to be refinanced through the issuance of rate reduction bonds. The bonds will mature no later than 12/31/11. Beginning 1/1/00, all utility customers will be charged a new competitive transition assessment to pay the debt service on the rate reduction bonds and approved stranded costs that are not eligible to be funded with the proceeds of the rate reduction bonds. The assessment will be charged until the bonds are paid in full and stranded costs are fully recovered by the utilities.
Illinois	H.B. 362	Utilities may use securitization to finance transitional costs or stranded costs. Commission must approve of securitization as long as the proceeds of sale will be used to: 1) refinance debt, equity or both reducing capital; 2) retire fuel contracts for nukes; or 3) fund debt services to pay for costs associated with above. Funding charges for securitization can only be collected until 12/31/08.

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Divestiture of Generation Assets		
Nevada	A.B. 366	A vertically integrated electric utility shall not provide a potentially competitive service except through an affiliate. The PUC shall establish limitations on ownership, operation, and control of the assets of a provider of an electric service to prevent anti-competitive conduct and ensure the development of effective competition. Such conditions and limitations may include limitations on the ownership, operation, and control of transmission facilities and any generation necessary to the reliable and economic operation of such transmission facilities. An affiliate may provide a potentially competitive service if PUC finds there is an arm's length transaction that will not adversely affect effective competition and the risk of anti-competitive behavior, and the regulatory expense to prevent such behavior, is minimal; PUC shall adopt procedure to process ar affiliate request to provide potentially competitive service and shall make any required findings no later than 6 months before authorizing retail competition. (Section 39, p. 12; Sections 41-43, p. 15-16)
California	H.B. 1890	Essential to separate monopoly transmission function from competitive generation operations by use of ISO. PUC must approve retention of generation assets in same corporation with distribution assets after market valuation. (p. 29, 61)
Maine	H-568, (LD 1804)	On or before 3/1/00, each investor-owned utility shall divest all generation assets and generation-related business activities other than contracts with QFs or demand side management providers, facilities located outside the U.S., or generation assets PUC determines necessary for the utility to perform its transmission and distribution obligations. No later than 1/1/99, each utility shall submit to the PUC a plan to accomplish divestiture. PUC shall review the plans and, by 7/1/99, issue an order approving or modifying the plan. Utility may apply for an extension beyond 3/1/00. PUC shall grant an extension if the extension would improve the sale value of the assets. If extension is granted, utility shall transfer generation assets to a distinct corporate entity by 3/1/00. After 2/28/00, each utility shall sell rights to capacity and energy from all generation assets except those necessary to perform its transmission and distribution obligations. PUC shall adopt rules governing the procedure for divestiture. PUC shall require distribution utility to divest an affiliated competitive provider if the utility or the affiliate has knowingly violated provisions of the Act and the violation resulted in or had the potential to result in substantial injur to retail consumers. If, after the effective date of the Act, 10 percent or more of the stock of a distribution utility is purchased by an entity, the purchasing entity and any affiliate may not sell or offer generation service to any retail customer and, if the PUC determines that an affiliated provider obtains an unfair market advantage as the result of such a purchase, the PUC shall order the distribution utility to divest the affiliate. If PUC orders a distribution utility to divest an affiliate, the distribution utility may not have an affiliated interest in a competitive provider after the divestiture. (p. 2, 7, 11-12)
Montana	S.B. 390	To the extent a utility is vertically integrated, it shall functionally separate electricity supply, retail transmission, and distribution. PSC may approve functional separation but may not order divestiture or prohibit it. Utilities shall prevent undue discrimination in favor of own power suppl and prevent any form of self-dealing that could result in noncompetitive electricity prices. Utilities must grant customers and suppliers access to the utilities' retail transmission and distribution systems on a nondiscriminatory, comparable basis. Utilities may satisfy these provisions if the adopt a code of conduct consistent with the FERC-approved code of conduct. Similar provisions apply to co-ops. (p. 2, 5, 9)
New Hampshire	H.B. 1392	Restructuring should require at least functional separation of generation from transmission and distribution services. However, distribution companies should not be entirely precluded from owning small-scale distributed generation resources. PUC authorized to require that distribution and power supply services be provided by separate affiliates. (p. 2, 4, 11)
Oklahoma	S.B. 500	A primary goal of a restructured electric industry is to encourage development of competition through separation of generation services from transmission and distribution services. Entities what own both transmission and distribution, as well as generation facilities, shall not be allowed to use any monopoly position in these services as a barrier to competition. Generation services shall be functionally separated from transmission and distribution services. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring, which shall include but not be limited to examination of unbundling of generation, transmission and distribution services, and market power. (p. 4, 6)
Pennsylvania	H.B. 1509	PUC may permit but cannot require a utility to divest facilities or reorganize its corporate structure. (p. 33-34)

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Divestiture of Generation Assets (cont.)		
Rhode Island	96-H 8124 Sub. B	By 1/1/97, distribution companies must file plan with PUC to transfer ownership of generation facilities to separate affiliates. Every wholesale power supplier receiving contract termination fees must subject its generating facilities to market valuation through lease, sale, spin-off or other method. At least 15 percent of such facilities must be disposed of through this process. If company is subject to a higher requirement in another state's restructuring proceeding, same amount will apply in Rhode Island. Implementation methodology must be filed with PUC by 7/1/97. Employees of distribution company must function independently of affiliated non-regulated power company under detailed standards of conduct (p. 17, 31-32, 35-38)
Massachusetts	H.B.5117	Optional divestiture, although encouraged by DTE as a good way for utility to rid itself of nuclear related stranded costs. Non-nukes must be sold at auction or sale. Proceeds from sale of generation, net of tax effects, should be applied to reduce amount of transition costs. Affiliates must be separate entities.
Connecticut	H.B. 5005	The state's electric companies must unbundle and separate their power generation assets from their transmission and distribution assets. Utilities must divest their nonnuclear generation by 1/1/00, sell their nuclear generation assets and mitigate their costs in order to be eligible to claim any stranded costs. By 1/1/00, DPUC must establish a competitive transition assessment (CTA) for each distrib co. to recover DPUC-approved stranded costs. The CTA will be applied to all customers.
Illinois	H.B. 362	

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Treatment of Stranded Costs		
Nevada	A.B. 366	When PUC determines an electric utility providing noncompetitive service cannot meet the conditions to also provide a potentially competitive service, utility has reasonable opportunity to recover previously incurred costs of those services it elects not to provide in future. The PUC shall determine the recoverable costs associated with assets and obligations documented in the accounting records of a vertically integrated electric utility that are properly allocable to a particular potentially competitive service as of the date alternative sellers begin providing such service in this state. Shareholders of the utility must be fully compensated for all such costs determined by the PUC. In determining the recoverable costs, the PUC shall take into account extent utility was legally required to incur cost; extent market value exceeds costs for assets and obligations; mitigation efforts; extent to which previous rates have already compensated shareholders for risk of non-recovery; tax effects; and, where utility had discretion to incur costs, its performance relative to similar utilities. PUC may impose a non-bypassable mechanism for recovery and determine time period for recovery. Such determinations and procedures must not discriminate agains a market participant. (Section 43, p. 16; Section 46, p. 18)
California	H.B. 1890	Fair opportunity to fully recover costs of PUC approved generation-related assets, including work force realignments and buyouts of certain existing power contracts. PUC to identify and determine costs and categories that may become uneconomic. Such costs are recoverable from all customers on a non-bypassable basis. Calculation based on book cost net against market value. Departing customers pay a severance fee; remaining customers pay a competitive transition charge (CTC) based on customer usage. CTC ends for most costs on 12/31/01; employee related cost recovery extends to 12/31/06. "Firewall" protects customers in one class from absorbing CTC exemptions granted in other classes. If local publicly owned utility elects not to allow retail competition, it cannot recover stranded costs. (p. 5, 31, 45-53, 60, 89-90)

Source: http://www.ncsl.org/programs/esnr/compare.htm
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Treatment of Stranded Costs (cont.)		
Maine	H-568, (LD 1804)	Stranded costs: a utility's legitimate, verifiable, and unmitigable costs made unrecoverable as a result of restructuring and determined by the PUC. For each utility, PUC shall determine the sum of the following to the extent they qualify as stranded costs: costs of utility's regulatory assets related to generation; difference between net plant investment associated with generation assets, and the market value of generation assets; difference between future contract payments and market value of the utility's purchased power contracts. When determining market value of generation assets and purchased power contracts, PUC shall rely to the greatest extent possible on market information. PUC may not include any costs for obligations incurred on or after 4/1/95, except: regulatory assets created after 4/1/95 and prior to 3/1/00, for amortization of costs associated with restructuring a QF contract; costs deferred pursuant to rate plans; energy conservation costs; obligations incurred after 4/1/95, and prior to 3/1/00, that are beyond the control of the utility; and obligations incurred after 4/1/95, to reduce potential stranded costs. Utility must pursue all reasonable means to reduce potential stranded costs and to receive highest possible value for assets and contracts. PUC shall consider utility's efforts to mitigate when determining amount of stranded costs. PUC shall provide utility a reasonable opportunity to recover stranded costs through rates of transmission and distribution. Nothing in the Act may be construed to give a utility a greater or lesser opportunity to recover stranded costs than existed prior to retail access. Before retail access begins, PUC shall estimate stranded costs of each utility. PUC shall use these estimates as the basis for a stranded costs charge to be charged by each transmission and distribution utility when retail access begins. In 2003, and every 3 years thereafter until utility is no longer recovering adjustable stranded costs, PUC shall correct any substantial inaccuracies in the estimates and adjust the charges to reflect the correction. Any change will be prospective only and may not reconcile past estimates to reflect actual values. PUC shall set an amount of recoverable, stranded costs after calculating the net aggregate value of all divested assets that had proceeds exceeding book costs against the aggregate value of all other stranded generation assets. Commission may not shift cost recovery among customer classes in a manner inconsistent with existing law. PUC shall conduct separate adjudicatory proceedings to determine stranded costs for each utility. In the same proceeding, PUC shall establish stranded cost charges for each utility. Customer who significantly reduces or eliminates consumption due to self-generation, conversion to alternative fuel or DSM, may not be assessed an exit or entry fee in any form. Absent other just cause, a layoff after 3/1/00 is deemed to be a result of retail competition. Each utility must file a plan with the PUC prior to the beginning of retail access providing transition services and benefits for eligible employees. Such benefits include programs to assist employees in maintaining fringe benefits, up to 2 years of retraining and out-placement services, full tuition for 2 years at the University of Maine or a comparable technical school at the discretion of the employee, 24 months of continued health care insurance, and severance pay equal to 2 weeks of base pay for each year of full-time employment. The plan may include provisions for early retirement benefits. PUC shall allocate the reasonable accrual incremental cost of such benefits to ratepayers through charges collected by the transmission and distribution utility. All charges must be transferred to a system benefits administrator in the transmission and distribution utility and used to provide the benefits and services provided for in the Act. (p. 13-15, 21-22)
Montana	S.B. 390	PSC shall allow recovery of transition costs including unmitigatable costs of QFs such as reasonable buyout or buy down, unmitigatable costs o energy supply-related regulatory assets and deferred charges, unmitigatable transmission costs related to generation and other power purchase contracts, except recovery of those costs is limited to the amount accruing during the first 4 years after the PSC approves a transition plan. Value of generation-related assets must be reasonably demonstrable and considered on a net basis. Methods for determining value include estimating future market values, independent third-party appraisal, and competitive bid sale. Transition charges must be imposed within a transition cost recovery period approved by the PSC on a case-by-case basis. Certain transition costs may have varying transition cost recovery periods. (p. 3, 6-7, 10)

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Treatment of Stranded Costs (cont.)		
New Hampshire	H.B. 1392	Defined: costs, liabilities, and investments utilities would reasonably expect to recover under existing regulatory scheme but which they will not recover in a competitive market. Limited to existing, PUC-approved renegotiated, or new PUC-mandated, commitments. Legislative intent to give PUC appropriate tools and guidance to address stranded costs. PUC shall balance interests of ratepayers and utilities. Nothing is intended to provide greater recovery than present law provides. Utilities should recover net nonmitigatable costs of environmental mandates and federally mandated QF contracts. Costs should be on net basis, verifiable, exclusive of transmission and distribution assets, periodically trued up. Recovery should be by nondiscriminatory, appropriately structured charge, fair to all customer classes, limited in duration, consistent with promotion of competitive markets, applied only to customers within the distribution utility's service territory. Entry and exit fees are not preferred mechanisms. PUC may establish interim recovery charge good for 2 years after compliance filing, to be netted against final recovery charges. Interim charge sets no precedent for amount of final recovery charge.(p. 4, 7-8, 10-11)
Oklahoma	S.B. 500	A procedure shall be established for identifying and quantifying stranded costs and for allocating such costs. Mechanisms shall be proposed for recovery of an appropriate amount of prudently incurred, unmitigatable, verifiable stranded costs. Each entity must propose a recovery plan that establishes its unmitigatable, verifiable stranded costs and a limited recovery period designed to recover costs expeditiously, provided that the recovery period and amount of transition costs shall yield a transition charge that shall not cause total price, including transmission and distribution services, for any consumer to exceed the cost per kW hour paid on the date of this Act during the transition period. Transition charge shall be applied to all consumers including direct access consumers, shall not disadvantage one class or supplier over another, shall not impede competition, and shall be allocated over a period of not less than 3 nor more than 7 years. No later than 1/1/99, Commission shall commence a study of financial issues related to restructuring, which shall include but not be limited to the examination of stranded costs and their recovery, and a final report shall be provided to the legislative task force no later than 12/31/99. (p. 6-7)
Pennsylvania	H.B. 1509	Fair opportunity to fully recover amount of stranded costs PUC determines to be just and reasonable. PUC determines level of each utility's stranded costs to be collected through a non-bypassable CTC applied to all customers accessing transmission and distribution systems. PUC must adhere to specifically enumerated principles in determining amount. Calculation based on utility's known and measurable net generation-related cost determined on net present value basis over life of asset that may become uneconomic despite mitigation efforts. Includes prudently incurred costs of work force realignments and power contract buyouts and excludes any costs previously disallowed by PUC as imprudent. (p. 21-22, 24, 26-27, 35-36, 49-52)
Rhode Island	96-H 8124 Sub. B	Utilities should have a reasonable opportunity to recover prudently incurred transition costs. Distribution companies who purchase wholesale power under an all-requirements contract are authorized to terminate the contract and pay a termination fee. Such payments are recoverable from all customers through a non-bypassable transition charge. Charge may include costs of regulatory assets, nuclear obligations, buyout of above market power contracts, net unrecovered commitments, and capital costs of generating plants. Charge continues until liabilities are satisfied, with true up calculations. Recovery time for certain specified components is limited to period from 7/1/97 to 12/31/09. From 7/1/97 to 12/31/00, charge shall recover 2.8¢/kWh, thereafter in an amount set by PUC.(p. 3, 20, 28-30)
Massachusetts	H.B.5117	Use of securitization by distribution company would require approval by DTE and is subject to achievement of mitigation efforts satisfactory to DTE. But, use of securitization may only be used if distrib. co. demonstrated that rate reductions stemming from securitization would not be financially viable without securitization.

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Treatment of Stranded Costs (cont.)		
Connecticut	H.B. 5005	To have stranded costs approved, the utility must take reasonable steps to mitigate the costs, including seeking to have the purchasers of generation assets offer employment to those employed by the divested generating facility and making good faith efforts to negotiate the buyout, buydown or renegotiation of power contracts. An electric company is eligible to claim stranded costs in connection with its nonnuclear generation assets only if it divests them. The DPUC will calculate the stranded costs for generation-related regulatory assets to be their book value as of 1/1/00. Stranded costs for long-term contract costs that have been reduced to a fixed present value through the buyout, buydown, or renegotiation of independent power producer contracts and purchased power contracts approved by FERC will be calculated at their present value and the DPUC will then net purchased power contracts approved by the FERC that are below market value against any contracts that are above market value. Stranded costs for nonnuclear generation assets will be calculated by the DPUC to be the difference between the book value and the market value of an efficiently managed, comparable nonnuclear generating facility in a competitive market. A distrib co. can apply to DPUC to retire Millstone I for economic reasons. DPUC must allow any recovery ordered to be recovered through a CTA. Other nuclear power plants must be operating for recovery of the stranded costs associated with them. Companies must put plants up for auction by 1/1/04 if they want to continue recovery of associated stranded costs.
Illinois	H.B. 362	Residential: Graduated transition chg. decreases annually during the period 2002-2006. Non-Residential: .05 cents/kWh in ’99 increases to .9 cents/kWh in 2006. Intangible transition assets can be securitized. Collection of transition costs can continue to 2008, 2010,if determined to be in public interest. The amt. Securitized cannot exceed 50% of total capitalization ($7 billion for ComEd, $1.8 billion for IP)

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Reciprocity		
Nevada	A.B. 366	PUC to issue a quarterly report to legislature evaluating, among other issues, opportunities to cooperate, formally or informally, with other states or with the Federal Government in the implementation of competition. (Section 53, p. 23)
California	H.B. 1890	For a utility to sell to another utility's customers, it must allow access to its own customers. Out-of-state utilities must enter into a compact to adhere to enforceable reliability protocols to be allowed to sell to California retail customers. (p. 29, 90-91)
Maine	H-568, (LD 1804)	
Montana	S.B. 390	All suppliers must be afforded open, fair, and nondiscriminatory access to customers and a comparable opportunity to compete. Distribution service providers or affiliates may not use another distribution service provider's facilities unless the first provider offers comparable, nondiscriminatory access to its distribution facilities. Co-ops that elect not to participate in retail access may not use utilities' distribution systems unless there is a pre-existing contract. (p. 11, 14)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	Any municipal corporation may voluntarily become subject to the provisions of the Act through a non-revocable election. Any municipal corporation that elects not to participate shall be prohibited from extending retail electric distribution service beyond its corporate limits with the exception that it may continue to offer retail distribution service from lines owned on the Act's effective date. (p. 4, 9)
Pennsylvania	H.B. 1509	No entity regulated by the PUC may use the transmission or distribution system of another PUC regulated entity to supply electricity to an end-use customer unless the first entity allows the other entity to sell to its customers. (p. 38-39)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B.5117	All suppliers must be given open access to customers and the ability to compete. The Commonwealth should enter into compact with other New England state and N.Y. that provides incentives to sell electricity to MA retail customers. But protects reliability of regional transmission and distribution
Connecticut	H.B. 5005	Municipal companies cannot restructure unless they want to sell outside their service territories. If they decide to do this, they must open their markets to competitors. Municipals account for only 4% of the market in CT.
Illinois	H.B. 362	Alternative suppliers may not: 1) deny service or offer different terms, rates, etc. to anyone or group; 2) deny service based on locality or change rates etc. based on locality. Electric Co. may serve customer outside service territory as long as customer is eligible for service from alternative and has expressed desire for alt. Service. They may also sell to customers previously served by municipal company. Municipal CO's are exempt from state jurisdiction.

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Customer Aggregation		
Nevada	A.B. 366	Customers may begin obtaining aggregation services from an alternative seller no later than 12/31/99, unless the PUC determines that a different date is necessary to protect the public interest. (Section 29, p. 11; Section 39, p. 12)
California	H.B. 1890	All customer classes are entitled to aggregation on a voluntary basis. Can be done by private parties, or governmental entities. Public bodies acting as residential aggregators must offer to include everyone within the jurisdiction. (p. 43)
Maine	H-568, (LD 1804)	When retail access begins, consumers may aggregate in any manner they choose. If a public entity serves as an aggregator, it may not require consumers within its jurisdiction to purchase generation service from that entity. (p. 2-3)
Montana	S.B. 390	Aggregators may be licensed by the PSC to aggregate retail customer purchases. Aggregators take title to electric energy as an intermediary fo sale to retail customers. (p. 2)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	Permits PUC licensing of aggregators, brokers and marketers as suppliers of electric energy, including municipal corporations selling outside their municipal limits, to serve all customer classes. (p. 24, 53-56)
Rhode Island	96-H 8124 Sub. B	
Massachusetts	H.B.5117	Municipalities can aggregate, but cannot solicit customers of municipal companies. Cities and towns can aggregate on behalf of citizens.
Connecticut	H.B. 5005	By 1/1/00, the DPUC must propose standards and procedures to facilitate the aggregation of electricity loads and the aggregation of end use customers into buying groups.
Illinois	H.B. 362	Groups of customers can aggregate power needs and purchase electricity at bulk rates. However, customers included in aggregation must hav become eligible for choice.

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Unbundling		
Nevada	A.B. 366	PUC to determine which electric services are potentially competitive using a set of specified criteria. Retail customers will have direct access to such services. (Section 39, p. 12-13)
California	H.B. 1890	Each electric corporation shall propose a stranded cost recovery plan to the PUC, which must provide identification and separation of individual rate components. Bills shall disclose each component of the total charge. (p. 49, 62, 71)
Maine	H-568, (LD 1804)	Beginning 1/1/99, utility shall issue bills that state the current cost of electric capacity and energy separately from transmission and distribution charges and other charges for electric service. By 1/31/98, each utility shall file an unbundling proposal with PUC. Beginning 3/1/02, billing and metering services are subject to competition. PUC may establish an earlier date for competitive billing and metering services, but beginning date may not be prior to 3/1/00. (p. 3, 19)
Montana	S.B. 390	Electrical bills must disclose each component of the electrical bill in accordance with the rules promulgated by PSC. Bills must disclose distribution and transmission charges, electricity supply charges, competitive transition charges, and universal system benefits charges. (p. 14)
New Hampshire	H.B. 1392	Restructuring should require unbundling of prices and services. Customers should be able to choose options such as levels of reliability, real time pricing, and generation source. There should be clear price information on generation, transmission, distribution, and ancillary services. (p. 2, 4)
Oklahoma	S.B. 500	A primary goal of a restructured industry is to encourage unbundling of prices. Consumer choice means retail consumers shall be allowed to purchase different levels and quality of electric supply. When consumer choice is introduced, rates shall be unbundled to provide clear price information on generation, transmission, distribution, and ancillary charges. Bills for all classes shall be unbundled, utilizing line itemization to reveal various component costs of services. Charges for public benefit programs shall be unbundled and appear in line item format for all classes of consumers. (p. 3-5)
Pennsylvania	H.B. 1509	PUC must require unbundling of electric services, tariffs, and bills to separate charges for generation, transmission and distribution, and may require unbundling of other services. Customer bills must contain unbundled charges sufficient to enable consumer to determine basis for the charges. (p. 29-30, 47)
Rhode Island	96-H 8124 Sub. B	On or before 1/1/97, and effective 7/1/97, distribution companies shall file unbundled rates separately stating transmission, distribution and transition charges. Customer bills shall conspicuously display specified information, including transition and conservation charges, taxes, number of kWh consumed, cost of power, cost of distribution, and other costs. (p. 27, 49)
Massachusetts	H.B. 5117	As of 1/1/98, unbundled bills were sent to customers.
Connecticut	H.B. 5005	By 10/1/98, each electric company must submit a plan to the DPUC to unbundle and separate by 10/1/99, all of the utility's generation assets. Any nonnuclear generation assets that the utility does not intend to divest by 1/1/00 must be unbundled and separated by transferring them to one or more separate affiliates. Any nuclear generation assets that the utility does not intend to sell by 1/1/00 must be unbundled and separated by divesting them by 1/1/04, transferring them to one or more separate affiliates or to one or more divisions.
Illinois	H.B. 362	Three years from effective date of this Act, Commission will investigate the need for unbundling

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Consumer Education		
Nevada	A.B. 366	The PUC shall establish minimum standards for the form and content of all disclosures, explanations, or sales information disseminated by sellers of competitive services to ensure that consumers receive adequate, accurate, and understandable information about the service that enables them to make an informed decision relating to the source and type of electric service purchased. Such standards must not be unduly burdensome, must not unnecessarily delay or inhibit competition, and may establish different requirements for disclosures, explanations, or sales information relating to different services or similar services to different classes of customers wherever appropriate. Before commencement of direct access, the PUC shall carry out an educational program for consumers to inform them of changes in the provision of electric service, inform them of the requirements relating to disclosures, explanations, or sales information, and provide assistance in understanding and using the information to make reasonably informed choices. The PUC shall expend up to $500,000 from its reserve account to provide education and informational services to educate and inform residents The PUC shall contract with an independent person to provide such services. (Section 48, p. 19; Section 57, p. 24)
California	H.B. 1890	Electric corporations, in conjunction with PUC, shall devise and implement a customer education program. (p. 72)
Maine	H-568, (LD 1804)	PUC shall establish standards for publishing and disseminating, through any means considered appropriate, information that enhances consumers' ability to effectively make choices in a competitive market. PUC shall adopt rules implementing a consumer education program including the immediate organization of a consumer education advisory board to investigate and recommend methods to educate the public about retail access and its impact on consumers. PUC shall ensure broad representation from all customer classes including public agencies or the advisory board. Members serve without compensation. The advisory board must address level of funding for adequate educational efforts and source of such funding; aspects of retail access on which consumers need education; most effective means of accomplishing education of consumers; appropriate entities to conduct education efforts; and any other relevant issue regarding education of consumers. PUC shall consider the recommendations of the advisory board when adopting rules to implement a consumer education program. (p. 5, 19)
Montana	S. B. 390	Public utilities shall educate customers about choice so customers can make informed choices. The education process must give special emphasis to efforts during the transition period.
New Hampshire	H.B. 1392	PUC should ensure customer confusion is minimized and consumers will be well informed about changes. (p. 4)
Oklahoma	S.B. 500	Commission shall ensure that consumer confusion will be minimized and consumers will be well informed about changes resulting from restructuring and increased choice. (p. 4)
Pennsylvania	H.B. 1509	Each distribution company, in conjunction with PUC, must implement a consumer education program. PUC shall establish regulations to ensure suppliers provide adequate and accurate information to enable consumers to make informed choices. Information must be in an understandable format that enables comparison of price and service on a uniform basis. (p. 47-48)
Rhode Island		Distribution companies to notify customers of retail options at least 90 days prior to eligibility for retail access. (p. 25)
Massachusetts	H.B.5117	DOER will be primary agency in charge of consumer ed. DOER will provide a toll free hot-line for customers, and provide educational materials. Educational services will be approved by DTE to ensure they're not duplicative of educational/protection services provided by DTE's Consumer Division. Portfolio standards and disclosure of fuel sources, emissions etc. will be provided in standardized form for consumers to make supplie choices.
Connecticut	H.B. 5005	DPUC must establish a comprehensive education program. The cost of this program is covered by a systems benefits charge.
Illinois	H.B. 362	

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Consumer Protection		
Nevada	A.B. 366	Any alternative seller must have a PUC license, which may be limited, suspended, or revoked to protect the public interest. By 1/1/99, PUC to establish conditions alternative sellers must satisfy before selling to retail customers. Conditions relate to safety, electric reliability, financial reliability, fitness to serve customers, billing practices, and terms for establishing and terminating service. PUC to establish and implement standards of conduct related to activities inconsistent with goals of Act, including appropriate penalties for violation and procedures for imposing such penalties and referring potential violations to Attorney General or Justice Department. PUC shall establish procedures to ensure no customer is switched to another seller without reliable confirmation. (Section 40, p. 14; Section 42, p. 15-16; Section 48, p. 19)
California	H.B. 1890	Every entity offering power to small customers must register with PUC. All offers of service must include written notice of price and terms, including amount of CTC and right to rescind contract. Consumers can recover actual and punitive damages, including attorney's fees, for violations. No residential or small commercial customer's account can be switched to another provider without confirmation by an independent third party verification company. (p. 6, 43-44, 72-73)
Maine	H-568, (LD 1804)	PUC shall establish minimum standards to protect consumers. PUC shall license competitive electric providers. To issue a license, PUC must receive evidence of financial capability, ability to enter into binding interconnection arrangements with transmission and distribution utilities, disclosure of all pending legal actions and customer complaints filed during the prior 12 months, evidence of ability to satisfy the renewable resource portfolio standards, and disclosure of names and corporate addresses of all affiliates. PUC may also require a bond as evidence of financial ability to withstand market disturbances. PUC shall establish rules governing information disclosure for competitive providers. As a condition of licensure, provider supplying customers with a demand of 100 kW or less may not terminate generation service without 30 days' prior notice, must offer service for a minimum period of 30 days, must allow customer to rescind selection of competitive provider within 5 days of initial selection, may not telemarketing services to a customer who has filed a written request not to receive such services, and must provide a customer with specified disclosure information within 30 days of contracting. PUC may limit the duration and scope of a license or ma revoke a license in the public interest. PUC shall establish by rule consumer protection standards to protect and promote market competition and to prevent fraud or other unfair and deceptive business practices. PUC may impose a penalty of up to $5,000 for each violation of any consumer protection rule. Each day of a violation constitutes a separate offense. If PUC has reason to believe that utility has violated any provision of law for which a criminal prosecution is provided or has violated any antitrust law of the state or the US, PUC shall notify the attorney general. Attorney general shall promptly institute any appropriate actions. A distribution utility may not release any proprietary customer information without the prior written authorization of the customer. Employees of a distribution utility may not state or provide any customer or potential customer opinion regarding reliability, experience, qualifications, financial capability, managerial capability, operations capability, customer service record, consumer practices, or market share of any affiliated competitive provider or nonaffiliated competitive provider. (p. 4-6, 9-10, 12)
Montana	S.B. 390	Public interest requires continued protection of consumers through licensure, provision of information, and a process for investigating and resolving complaints. Utilities shall maintain standards of safety and reliability of the electric delivery system. PSC may require proof of financial integrity, adequate reserves, and a license bond. PSC may revoke or suspend a license of an electric supplier or impose a penalty or both. If th supplier intentionally provided false information to PSC, switched electricity customer without written permission, failed to provide reasonably adequate supply of electricity, committed fraud, or engaged in deceptive practices, fine is not less than $100 or more than $1,000 for each violation. Each day of each violation constitutes a separate violation. PSC shall promulgate rules establishing procedures to prevent unauthorized switching of customers. Transitional advisory committee shall file annual report in 2000 that addresses the need, if any, for additional consumer protection including protection from abusive or anti-competitive practices. (p. 1, 11, 13-14, 16)
New Hampshire	H.B. 1392	Retail suppliers who do not own transmission and distribution facilities should at a minimum be registered with PUC. (p. 5)

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Consumer Protection (cont.)		
Oklahoma	S.B. 500	Appropriate rules shall be promulgated ensuring that reliable and safe electric service is maintained. Minimum residential consumer service safeguards and protections shall be ensured. No later than 1/1/98, Commission shall commence study of technical issues related to restructuring including but not limited to reliability and safety. Final report shall be provided to legislative task force no later than 12/31/98. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of consumer safeguards and licensing of retail suppliers. Final report shall be provided to legislative task force no later than 8/31/00. All retail suppliers shall be required to meet certain minimum standards designed to ensure reliability and financial integrity and be registered with Commission. There shall be no customer switching between distribution providers from the date of this Act until 7/1/02, except by mutual consent of all affected parties. (p. 4-7, 9)
Pennsylvania	H.B. 15	Each generation supplier required to obtain PUC license and post bond or other security to ensure financial responsibility. PUC to establish regulations to prevent customer account transfer without direct oral confirmation or written consent. PUC to monitor market for anti-competitive conduct; investigate complaints or potential violations and refer them as necessary to the appropriate state or federal prosecutors; deny proposed mergers, acquisitions, dispositions, or other transactions that are anti-competitive or discriminatory. (p. 21, 47, 53, 67-69)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, electric licensing committee to submit proposals to legislature for consumer protection. All non-regulated power producers must file registration application with division listing specified information and showing evidence of financial soundness such as surety bonds or other mechanisms specified by division. On request, distribution company must release names and addresses of customers to power producers who will be eligible for retail access within next 60 days, unless customer has requested in writing that information not be released. (p. 22, 24, 26)
Massachusetts	H.B.5117	DTE's Consumer Division will continue to protect consumers and ensure that distribution companies adhere to rules and regulations concerning billing and termination procedures. Alternative supplier can only serve customers after receiving a Letter of Affirmation stating that the customer desires the alternative supplier.
Connecticut	H.B. 5005	By 1/1/99, the DPUC is required to develop licensing procedures for sellers of electricity using the transmission and distribution facilities of an electric company. Suppliers must demonstrate their technical and managerial competence and meet a variety of environmental, consumer protection and labor provisions.
Illinois	H.B. 362	Utility companies retain obligation to serve residential and small commercial customers. If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. Supplemental low-income Energy Assistance Fund will be established from surcharge on bills ($.40/mo for residentials, $4.00/mo for non-residentials and $300/mo for large industrials). Energy Assistance Program Design Group will design low-income energy efficiency programs.

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Universal Service/Low-Income Assistance Program		
Nevada	A.B. 366	An electric distribution utility shall provide all noncompetitive services within its territory unless the PUC authorizes another entity to provide the noncompetitive service. PUC to establish minimum terms and conditions under which any customer not using an alternate seller will receive electric service. PUC shall designate utility to provide service to customers who do not elect or are unable to obtain alternative seller. Procedures may include, but are not limited to, requiring utility to serve such customers, requiring each alternative seller to serve a share of such customers, competitive bidding to select one or more providers. If the provider is an electric utility, the service shall be provided through ar affiliate whose sole business is provision of basic service. (Section 44, p. 17; Section 45, p. 18)
California	H.B. 1890	Such programs must continue to be funded at not less than the 1996 authorized levels. (p. 6, 65-67)
Maine	H-568	The policy of the state is to ensure adequate provision of financial assistance. In order to continue existing levels of financial assistance for low-income households and to meet future increases in need, PUC shall receive funds collected by all transmission and distribution utilities at a rate set by the commission in periodic rate cases and set initial funding for programs based on an assessment of aggregate customer need. If legislature appropriates financial support for households and individuals receiving assistance from the general fund, PUC may not terminate the assistance provided by transmission and distribution utilities unless the general fund source has completely replaced such assistance. On or before 1/1/98, PUC and state planning office shall provide the legislature with recommendations to fund assistance to low-income consumers through the general fund or through a tax on all energy sources in the state. (p. 19-20, 26)
Montana	S.B. 390	Universal system benefits programs include cost effective local energy conservation, low-income customer weatherization, renewables and low-income energy assistance. Programs are paid for by a non-bypassable universal system benefits charge assessed at the meter. Programs are established to ensure continued funding of, and new expenditures for, conservation, renewables, and low-income assistance during the transition period and into the future. From 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for the calendar year ending 12/31/95 establishes the minimum annual funding level. Utilities receive credit for internal programs or activities that support renewables, conservation, or low energy assistance. Credits can be carried forward to future years. Minimum annual funding for low-income and weatherization is established at 17 percent of the utility's annual universal system benefits funding level. The utility's transition plan must describe proposals for benefit programs, including methodologies such as cost effectiveness and need determination used to measure the utility's level of contribution to each program. Customers with loads greater than 1000 kW pay a charge equal to the lesser of $500,000, less credits, or .9 mills per kWh x the customer's kWh purchases, less credits. Utilities must submit an annual summary report relating to system benefit programs to the PSC and the transition advisory committee. Co-ops may collectively pool statewide credits to satisfy annual funding requirements. On or before 7/1/02, transition advisory committee and PSC shall reevaluate system benefits programs and make recommendations to the legislature regarding future need for such programs. On or before 11/1/98, the transition advisory committee shall make recommendations to the governor and legislature regarding low-income assistance programs. Recommendations may include assignment of agency or private nonprofit entity to administer fund. (p. 2-4, 11-12, 16)
New Hampshire	H.B. 1392	Distribution utility has obligation to connect all customers and to maintain minimum residential service safeguards, including low income assistance. A non-bypassable, competitively neutral system benefits charge applied to distribution may be used to fund low income programs. (p. 5)

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Universal Service/Low-Income Assistance Program (cont.)		
Oklahoma	S.B. 500	"Public benefit programs" means all social, economic, and environmental programs currently funded through rates charged to consumers. Entities providing distribution services shall be relieved of their traditional obligation to provide electric supply but shall have a continuing obligation to provide distribution service to all consumers within existing service territories. Firm service territories shall be fixed by a date certain if not currently established in law. Minimum residential consumer service safeguards and protections shall be insured including programs and mechanisms that enable residential consumers with limited incomes to obtain affordable essential electric service and the establishment of a default provider for any distribution customer who has not chosen an alternative supplier. Commission shall consider establishment of a distribution access fee assessed to all consumers to cover social costs, capital costs, and operating costs. No later than 1/1/99, Commission shall commence study of financial issues related to restructuring including but not limited to stranded benefits and their funding. Final report shall be provided to legislative task force no later than 12/31/99. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect. Final report shall be provided to legislative task force no later than 8/31/00. (p. 3, 5, 7)
Pennsylvania	H.B. 1509	State must at a minimum continue current protections and policies to assist low-income customers. PUC shall ensure that universal service is appropriately funded in each distribution territory and shall encourage the use of community-based organizations with necessary experience to be direct providers of programs that assist low-income customers. PUC shall establish an appropriate cost recovery mechanism for each utility to fully recover universal service costs. Distribution company remains provider of last resort unless PUC approves alternative. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. (p. 20, 22, 28, 34-35, 48-49)
Rhode Island	96-H 8124 Sub. B	Current special rates and protections shall continue. Within 3 months after 40 percent of kWh sales in New England are available for retail access, distribution company shall arrange a last resort power supply for customers unable to receive power under the standard offer or elsewhere. Company shall periodically solicit bids for power at market prices plus a fixed contribution from the company, subject to PUC approval. Company's fixed contribution is recoverable in rates charged all other customers. Company can terminate for nonpayment pursuant to PUC regulations. Authorized performance-based rate increases for distribution companies between 1/1/97 to 12/31/98 cannot be applied to low-income customers. (p. 3, 27-28, 35, 43)
Massachusetts	H.B.5117	Default service will ensure that customer will be served by incumbent supplier. Rate shall never exceed the avg. monthly market price of electricity. Payment options and rates charged for default service will remain uniform for up to 6 months. Ratepayer Parity Trust Fund will be established to subsidize low-income rates from monthly benefits surcharge on customers' bills.
Connecticut	H.B. 5005	Universal Service: Default and back-up service is required of distrib co's. Standard offer rate is available to all customers. Low-income: Include bars on discrimination on basis of income and redlining, a requirement that the state budget agency open the state electricity purchasing pool to people on public assistance. The ban is extended to include preventing winter shut-offs. The low-income programs, studies and other efforts are funded through a systems benefits charge. Utility companies retain obligation to serve residential and small commercial customers.
Illinois	H.B. 362	If a customer leaves and returns to be served by initial utility company, that company must serve the customer at the market price and guarantee service for up to 24 months. Supplemental low-income Energy Assistance Fund will be established from surcharge on bills ($.40/mo for residentials, $4.00/mo for non-residentials and $300/mo for large industrials). Energy Assistance Program Design Group will design low-income energy efficiency programs.

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Renewable Energy, Conservation, and Environmental Issues		
Nevada	A.B. 366	The PUC shall establish portfolio standards for domestic energy that set forth the minimum percentage of the total electricity sold during each calendar year that must be derived from renewable energy resources. The portfolio standards must require two-tenths of 1 percent of the total amount of electricity annually consumed by customers in this state as of 1/1/01 to come from renewables. This standard must be increased biannually thereafter by two-tenths of 1 percent of the total annual electric consumption until the standard reaches a total of 1 percent of the tota amount of electricity consumed. The electricity must be derived from not less than 50 percent renewable energy resources and be derived from not less than 50 percent solar renewable energy systems. Tradable renewable energy credits are allowed. Reporting requirements are established to ensure that all providers comply with the standards. A vertically integrated electric utility that has 9 percent of its electricity furnished by renewable energy resources on 1/1/97 is deemed to be in compliance until 1/1/05. Between 1/1/05 and 12/31/09, such a utility shall reach a total of one-half of 1 percent of the annual amount of electricity consumed, in annual increments of one-tenth of 1 percent, from solar energy resources. (Section 52, p. 22-23)
California	H.B. 1890	PUC must require each electric corporation to identify a rate component to fund energy efficiency, public interest research and development, and demand side management in specified yearly amounts that total $540 million through 3/31/02. The funds are to be held by the Energy Commission until further legislative action. Consumers can make voluntary contributions through their monthly bills to support such programs. (p. 6, 61-67)
Maine	H-568	Renewable resources are defined as total power production capacity not exceeding 100 mW and relying on fuel cells, tidal power, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste generators. Each competitive provider must demonstrate that no less than 30 percent of its portfolio of supply sources is derived from renewable resources. PUC shall review the 30 percent requirement and make a recommendation for any change to the joint standing legislative committee no later than 5 years after the beginning of retail competition. PUC shall require utilities to implement energy conservation programs. (p. 15-17)
Montana	S.B. 390	Public interest requires continued protection of consumers through funding for public purpose programs for energy conservation, weatherization, and renewable resource projects and applications. Such programs are paid for with a universal system benefits charge assessed at the meter. Beginning 1/1/99 through 7/1/03, 2.4 percent of each utility's annual retail sales revenue for the calendar year ending 12/31/95, is the minimum annual funding level for total system benefits programs, and 17 percent of that minimum must be used for low-income assistance programs, including weatherization. The balance may be used for other benefit programs such as energy conservation and renewables. Customers with loads greater than 1000 kW pay a system benefit program charge equal to the lesser of $500,000, less credits, or .9 mills per kW hour x the customer's kWh purchases, less credits. Credits can be carried forward into future years. Customers are entitled to credits for expenditures on renewable energy or conservation-related activities that are part of internal utility programs or activities. Utilities must submit an annual summary report to PSC and transition advisory committee detailing activities relating to all system benefit programs. On or before 7/1/02, PSC and transition advisory committee shall reevaluate ongoing need for such programs and make future needs recommendation to legislature. (p. 2-4, 11-12, 16)
New Hampshire	H.B. 1392	Overall policy goal is to implement restructuring with minimum adverse consequences to environment. Continued environmental protection and long-term environmental sustainability should be encouraged. A non-bypassable, competitively neutral system benefits charge applied to distribution may be used to fund energy efficiency, research and development, and investments in new technologies, as determined by the PUC Increased future commitments to renewables should be consistent with existing state energy policy and be balanced against impact on rates. Over the long term, renewables can have significant environmental, economic, and security benefits. Customers should be able to pay a premium for renewables. Incentives should be provided for demand side management. (p. 2, 5-7)
Oklahoma	S.B. 500	

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Renewable Energy, Conservation, and Environmental Issues (cont.)		
Pennsylvania	H.B. 1509	From 1/1/97 until 12/31/01, each distribution company must include a 2.3 mills per kWh charge to fund demand side management and renewables. PUC shall determine allocations of funds between the two categories. PUC, at its own discretion, may increase the sums after notice and public hearing. City where a generation plant has been proposed may request builder to fund study of environmental effects of proposed facility, up to lesser of $100,000 or .1 percent of estimated capital cost of project. (p. 43, 52-53)
Rhode Island	96-H 8124 Sub. B	Energy efficiency benefits charge assessed to all but muni electric company customers for DSM over five years starting 3/1/98 ($.0033/kwh in '98, to $.0025/kwh by 2002). Competitive procurement process must be used.
Massachusetts	H.B.5117	DOER will oversee and coordinate energy efficiency programs. Renewables will be funded by vacillating annual rate of $.00075/kwh to $.0005/kwh by 2002. Funds would be deposited in "Massachusetts Renewable Energy Trust Fund". Renewables portfolio will be established by DOER. DOER will oversee and coordinate ee programs. Minimum requirements for retail suppliers for new renewables: 1% of sales by 2003, o within one year of any renewable being within 10% of the avg. spot mkt price; an additional .5% per year through 2009; an additional 1% per year until a date determined by DOER. Hydro and municipal solid waste don't count toward new renewables requirement, but may count toward a portfolio standard to be determined by DOER for all renewables, including existing. A study was ordered to be conducted by department of revenue on the following tax deduction options: customers purchasing renewable energy in excess of minimum requirements under renewables portfolio standard, could take tax deduction of 50% of above market price. Business customers would get 25% tax deduction. Individual or business purchasing energy efficiency equipment would be eligible for a 20% deduction up to $10,000. Businesses would be eligible for 10% up to $50,000. Performance standards for fossil fuel plants will be drawn up by EPA with adoption by at least 3 other northeast states. Assessment against all nukes will be at least $90,000 to be used for radiation control program. Th performance standards for fossil fuel plants must include at least one pollutant by 2003, or earlier if adopted by 3 other states. The state Dept. o Environmental Protection, in conjunction with the A.G. shall promulgate standards for any pollutant determined by the DEP to be of concern to public health, and produced in quantity by electric generation facilities.
Connecticut	H.B. 5005	DPUC must establish a 0.3 cents per kilowatt-hour charge to fund energy conservation programs and a charge rising to 0.1 cents per kilowatt-hour to fund investments in renewable technologies. The Department of Environmental Protection must develop emission standards for pollutants for generating plants serving the Connecticut market, whether they are located in the state or elsewhere. The standard for a pollutant goes into effect when adopted by three northeastern states having a total population of at least 27 million. There is a Renewables Portfolio Standard that preserves the level of existing renewables, 5.5% of sales, and requires sales from those (or other renewable) technologies to increase to 7% by 2009. Sales from Class I renewables (solar, wind, sustainable biomass, fuel cells) must equal .5% per year to 3% by 2006; and an additional 1% per year to 6% by 2009.
Illinois	H.B. 362	Renewable Energy Resources Program will be administered by Dept. of Commerce and Community Affairs. Grants, loans and other incentives for investment in renewable energy resources. Report will be made to the General Assembly on the use and potential of renewables. As of 1/198 "Renewable Energy Resources and Coal Technology Development Assistance Charge" will be assessed customers. $.05/mo for residential, non-residential and gas customers; $37.5/month for non-residential electric and gas customers. Environmental protection: $100 million over 10 years for development of renewable energy resources and coal technology. $10 million in annual funding through surcharge on bills. Energy Efficiency Trust Fund: As of 1/1/98, this trust fund will consist of the pro-rata share of $3 million based on kWh sales from each supplier. By 4/1/99, every supplier with nuclear generation must file a tariff indicating the kWh sales for those facilities for decommissioning expense purposes.

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Treatment of Transmission and Distribution (T&D)		
Nevada	A.B. 366	A public entity does not become subject to the provisions of Sections 28-53 solely because the entity provides transmission or distribution service to an alternative seller except that the public entity shall provide such transmission and distribution services on an open and nondiscriminatory basis to alternative sellers in accordance with standards the PUC may establish by regulation. The PUC shall require each provider of a noncompetitive service that is necessary to the provision of a potentially competitive service to make its facilities or services available to all alternative sellers on equal and nondiscriminatory terms and conditions. The PUC may establish standards of conduct to prevent anti-competitive activities and such standards of conduct may include limitations on the ownership, operation, and control of transmission facilities and any generation necessary to reliable and economic operation of such transmission facilities. The PUC shall adopt regulations ensuring that a person who owns a transmission or distribution facility makes the facilities available on equal and nondiscriminatory terms and conditions to all alternative sellers or customers of alternative sellers. The Colorado River Commission may sell electricity or provide transmission or distribution service to customers who it was not serving or with whom it did not have a contract on the effective date of the relevant provisions of the Act, if the Colorado River Commission allows its system for transmission and distribution to be utilized by other alternative sellers pursuant to such terms and conditions as the PUC may establish. PUC may conduct an investigation of the effect on the market of transmission congestion or constraints. (Section 40, p. 14; Section 41, p. 15; Section 42, p. 15; Section 44, p. 17; Section 50, p. 20)
California	H.B. 1890	Continues to be regulated. All customers and suppliers to receive open, nondiscriminatory, and comparable access. (p. 29-30)
Maine	H-568	Upon request from a competitive provider, PUC shall provide load data on a class basis that is in the possession of a T&D utility, subject to reasonable protective orders to protect confidentiality. Except as otherwise permitted, on or after 3/1/00, an IOU T&D may not own, have a financial interest in, or otherwise control generation or generation-related assets. After commencement of retail access, a large investor-owned T&D utility serving more than 50,000 retail customers may not sell electricity to any retail customer. An affiliated provider may sell to retail customers outside the service territory of the distribution utility with which it is affiliated and within the service territory of the distribution utility with which it is affiliated, except that the affiliate may not sell more than 33 percent of the total kWh sold within the service territory of the distribution utility. No later than 1/1/05, based on its evaluation of the development of the competitive retail sales market, PUC shall complete an evaluation of the need for the market share limitation and shall report its findings to the legislature. A distribution utility may not engage in joint advertising or marketing programs of any sort with its affiliated competitive provider. Employees of a distribution utility may not be shared with and must be physically separated from those of an affiliated competitive provider. A distribution utility and its affiliated competitive provider must keep separate books and records. All regulated products and services offered by a distribution utility, including any discount, rebate, or fee waiver, must be available to all customers and competitive providers simultaneously and without undue or unreasonable discrimination. (p. 3, 8-12)
Montana	S.B. 390	Distribution services providers must make distribution facilities available to all suppliers, providers, and customers on a nondiscriminatory, comparable basis; and be the emergency supplier of electricity and related services. When a distribution services provider acts as emergency supplier, the supplier that should have provided the power must reimburse the distribution company according to a prescribed formula. Distribution services providers are not required to purchase reserve supply to fulfill emergency obligations. Transmission services must also be available on a nondiscriminatory, comparable basis. If a co-op offers electricity competitively to customers using a utility's distribution facilities, the co-op must create an affiliated for-profit entity to serve those customers that allows the entity to be taxed at the same level as other for-profit suppliers. PSC shall regulate retail transmission and distribution services including establishment of just and reasonable rates, which may include performance-based rates. (p. 2, 6, 9-10, 12-13, 22)
New Hampshire	H.B. 1392	T&D should remain regulated for the foreseeable future. PUC to take necessary measures to ensure nondiscriminatory, comparable, and open access to T&D. (p. 4-5)

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Treatment of Transmission and Distribution (T&D) (cont.)		
Oklahoma	S.B. 500	A primary goal of a restructured industry is to enable suppliers to engage in fair and equitable competition through open, equal, and comparable access to T&D systems. Entities which own both T&D as well as generation facilities shall not be allowed to use any monopoly position in these services as a barrier to competition. Generation shall be functionally separated from T&D services, which shall remain regulated. Comparable access for retail suppliers competing with affiliates of entities supplying T&D shall be assured. Commission shall monitor companies providing T&D and take necessary measures to ensure no supplier of such services has an unfair advantage in offering and pricing such services. Benefits associated with implementing an independent system planning committee composed of owners of electric distribution systems to develop and maintain planning and reliability criteria for distribution facilities shall be evaluated. No later than 7/1/99, Commission shall commence study of consumer issues related to restructuring including but not limited to examination of service territories, obligation to serve, and obligation to connect, as well as rates for regulated services. Final report shall be provided to the legislative task force no later than 8/31/00. (p. 3-7)
Pennsylvania	H.B. 1509	Continues to be regulated as a natural monopoly. Distribution company remains provider of last resort unless PUC approves alternative. PUC shall require all transmission and distribution facilities to provide comparable open access to all customers and suppliers. There is a rebuttable presumption the distribution company can accommodate all requests for service from suppliers but does not have to install nonstandard equipment unless customer pays full cost of such facilities. While distribution company collects CTC, or until there is 100 percent direct access, company has full obligation to serve, including connection, delivery, and acquisition of power. After transition period, PUC shall adopt regulations defining obligation to serve. Company must accept returning customer on same terms and conditions as new applicant. Distribution company shall implement procedures to require suppliers to deliver sufficient power to meet supplier's customer obligations. Subject to PUC approval, company may require customer to pay for enhanced metering capability. (p. 22, 28, 34, 46, 48-49)
Rhode Island	96-H 8124 Sub. B	T&D companies must provide nondiscriminatory access on reasonable terms consistently applied to all customers. Distribution companies must terminate all requirements contracts with generators no later than 3 months after 40 percent of the kWh sales in New England are available for retail access and can only own or operate generation or transmission facilities through affiliates, with some specific exceptions. (p. 6, 17-19, 21)
Massachusetts	H.B.5117	T&D companies must provide nondiscrimination access on reasonable terms for all suppliers and customers. Transmission and distribution assets as of 12/31/96, or acquired thereafter, shall be transferred to transmission or distribution companies, respectively. Distribution companies will be prohibited from selling electricity at retail and from owning or operating transmission services. As of 3/1/98, DTE will designate service territories for distribution companies.
Connecticut	H.B. 5005	Transmission and distribution activities will continue to be regulated by the DPUC, but electric generation activities will not be regulated.
Illinois	H.B. 362	To ensure system reliability, the Commission, within 180 days of the Act must adopt rules and regs for T&D that establish the procedures for restoring T&D to customers.

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Legislative Oversight		
Nevada	A.B. 366	PUC shall issue a quarterly report to the legislature assessing developments in electric industry in Nevada. Report shall evaluate, at a minimum effectiveness of competition, compatibility of direct access with environmental goals, impacts of competition on each customer class relative to present structure, and opportunities to cooperate with other states or the Federal Government in implementation of competition. In the quarterly report for the first quarter of 1999, the PUC shall provide a comprehensive evaluation of the development of the markets for potentially competitive services since 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 53, p. 23; Section 335, p. 148; Section 336, p. 148)
California	H.B. 1890	Five-member oversight board composed of three gubernatorial appointees, one Senator, and one Assemblyman. Board oversees the ISO and Power Exchange and serves as the appeal board from ISO decisions. (p. 5, 34-36)
Maine	H-568	On December 31 of each calendar year, PUC shall submit to the joint standing legislative committee a report describing the PUC's activities in carrying out the requirements of the Act, and include draft legislation designed to modify the Act consistent with the public interest. The joint standing legislative committee having jurisdiction over utility and energy matters may report out legislation concerning electric energy restructuring to future legislative sessions. (p. 22, 26)
Montana	S.B. 390	Transition advisory committee consists of eight voting members, equally balanced by party: 4 appointed by Speaker and 4 appointed by Senate President. Non-voting advisory members include: the director of dept. of environmental quality; one public utilities appointee; and 1 representative each from consumers, cooperatives, and PSC. Governor appoints 1 each non-voting member from: industry, non-industrial consumers, organized labor, environmental/ conservation, low-income program provider, Indian tribes, power market industry. PSC, legislative counsel, and agencies provide staff. Committee meets quarterly and dissolves on earlier of date full transition is completed or 12/31/04 and shall: provide an annual report on or before 11/1/01 to governor, speaker, Senate president, and PSC; provide quarterly reports to legislature thru 1/1/99; analyze and report on transition to effective competition. Annual report in 2000 must evaluate pilot programs with loads under 1000 kWh and include legislative recommendations about best means to further encourage choice, market access, and need for additional consumer protection revisions. Criteria for evaluating effective competition are specified. On or before 7/1/02, committee and PSC shall reevaluate need for ongoing universal system benefits programs and make recommendations. On or before 11/1/01, committee shall determine whether Montana utilities have an opportunity to market outside the state comparable to the reverse. On or before 11/1/98, committee shall make recommendations to governor and legislature regarding low-income assistance programs. (p. 4, 12, 15-16, 27)
New Hampshire	H.B. 1392	Establishes 14-member legislative oversight committee, seven from each house, with 2-year terms. Committee to report annually on or before 11/1 to governor, legislature, and PUC. In conjunction with PUC, report shall address new legislation and proposed amendments to existing law to promote restructuring. (p. 12)
Oklahoma	S.B. 500	Act creates Joint Electric Utility Task Force composed of 14 members of the legislature, 7 each selected by Senate President and House Speaker. Task force may appoint advisory councils made up of representatives of interested parties. Task force shall direct and oversee studies by the Commission and the Tax Commission. Task force shall remain in effect until termination, which shall be no later than 1/1/03. Commission shall make reports to task force on independent system operator issues, technical issues, financial issues, and consumer issues no later than 2/1/98, 12/31/98, 12/31/99, and 8/31/00, respectively. Task force may make final recommendations to the governor and the legislature. The task force is authorized to retain consultants and experts to study the creation of an ISO and the benefits of establishing a Power Exchange, which would operate as a power pool. All studies and recommendations relating to the ISO shall be submitted to the task force on or before 2/1/98, and shall conform to FERC Order No. 888. (p. 8-9)
Pennsylvania	H.B. 1509	

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Legislative Oversight (cont.)		
Rhode Island	96-H 8124 Sub. B	On 1/1/98, and annually for next 4 years, PUC to file report with governor and legislature detailing developments in competitive supply market, estimated savings from retail competition, progress towards regional transmission agreement, reforms instituted by regional power pool, and status of restructuring in surrounding states. (p. 23)
Massachusetts	H.B.5117	DTE, DOER and any other agencies, task forces involved with the Legislature will be reported to on an annual basis, or as necessary, by restructuring process.
Connecticut	H.B. 5005	Companies and agencies are required to report on various issues to the Legislature. These include the status of competition, rates, reliability, environmental quality and dislocated workers.
Illinois	H.B. 362	On or before 12/31/99, and once every three years thereafter, the Commission shall monitor and analyze patterns of entry and exit to the marke and report its findings to the General Assembly. During 2001 through 2006, the Commission will prepare annual reports regarding the development of electric markets. Utility companies must report annually to legislature on their collection of transition charges, efforts to mitigate stranded costs and use of transition funding mechanisms. A Policy Advisory Council, established by the legislature, will analyze restructuring and ensure that requirements of the Act are met and advise legislature on the spending of the Fund monies.

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Taxes		
Nevada	A.B. 366	If two or more persons perform separate functions collectively needed to supply electricity to final customer and the property would be centrally assessed if owned by one person, it shall be centrally valued and apportioned. Proportion of the tax levied by each county shall be determined according to valuation of contribution of each person to aggregate valuation of property. However, this provision does not apply to QFs built before 7/1/97. Not later than 1/1/99, Department of Taxation shall report to legislature on effect of Nevada's tax policies on potential for effective competition, effect of competition on state and local tax revenues, and recommend new legislation to advance Act in competitively neutral manner with minimum impact on state and local tax revenues. (Section 278, p. 114-116; Section 335, p. 148)
California	H.B. 1890	
Maine	H-568, (LD 1804)	On or before 1/1/98, the PUC and the state planning office shall provide the legislature with recommendations concerning funds to assist low-income consumers through general fund appropriations or through a tax on all energy sources in the state. (p. 26)
Montana	S.B. 390	During 4-year transition period, utilities may accelerate amortization of accumulated deferred investment tax credits associated with T&D and general plant if earnings fall below 9.5 percent earned return on average equity. Revenue oversight committee shall analyze state and local tax revenue derived from previously regulated electricity suppliers that will enter the competitive market and report to legislature annually on how revenue to state and local government is changed by restructuring and competition. On or before 11/30/98, revenue oversight committee shall recommend legislative changes, if any, to address comparable state and local taxation burdens on all market participants. (p. 8, 10, 16, 21-22)
New Hampshire	H.B. 1392	
Oklahoma	S.B. 500	The Tax Commission shall study and fully assess the impact of restructuring on state tax revenues and all other facets of current utility tax structure both on the state and all other political subdivisions. Study shall include feasibility of a uniform consumption tax or other method of taxation. Tax Commission is expressly prohibited from promulgating any rule or order without prior express authorization from the legislature or legislative task force. In the event a uniform tax policy, which allows all competitors to be taxed on a fair and equal basis, has not been established on or before 7/1/02, effective date for customer choice shall be extended until such time as a uniform tax policy has been established. (p. 8)
Pennsylvania	H.B. 1509	Restructuring to be accomplished in a revenue neutral manner at a level necessary to recoup losses that may result form restructuring. (p. 57-66)
Rhode Island	96-H 8124 Sub. B	By 1/1/97, retail electric licensing committee shall submit plan to legislature for taxing and/or assessing distribution and transmission companies and non-regulated power producers. (p. 22)
Massachusetts	H.B.5117	Requires parent, affiliate, subsidiary to pay transition payments to municipality impacted by devaluing of power plant in which generation facility is located. Transition payments are calculated on a declining rate from 1998-2009 (percentage difference between local property tax value of th property as of 1/1/96 and the fair cash value of the property as of 1/1 of the year previous to the year during which calculation is made). Generation facilities would be subject to the full fair cash valuation by localities. Tax payment would be a payment-in-lieu-of-taxes.
Connecticut	H.B. 5005	The gross earnings tax as it applies to generation is eliminated but the tax rate on transmission and distribution services is increased. The CTA and SBC are subject to this tax. The corporation business tax and sales tax is amended to reflect the bill's changes to the electric industry. The gross earnings tax changes are effective 1/1/00. Electric suppliers, including aggregators, will receive a one-time credit of $1,500 against the state corporation business tax for each worker hired by the supplier who was displaced as a result of deregulation.
Illinois	H.B. 362	Sale, pledge, assignment or other transfer of intangible transition property shall be exempt from state and local taxes. A per/kWh use tax will be implemented, except for municipal corporations owning and operating a local transportation system for public service.

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Performance Based Rates (PBR)		
Nevada	A.B. 366	PUC shall adopt regulations permitting innovative methods of pricing noncompetitive services upon a finding that such methods would improve performance or lower costs. (Section 44, p. 17)
California	H.B. 1890	
Maine	H-568, (LD 1804)	
Montana	S.B. 390	PSC shall establish just and reasonable rates, through established rate making principles, for distribution and transmission services and shall regulate these services. PSC may approve performance-based rate making on a demonstration by utilities that the alternative methods comply with the utilities' transition plans. (p. 13)
New Hampshire	H.B. 1392	Performance-based or incentive regulation should be considered for transmission and distribution services. (p. 4)
Oklahoma	S.B. 500	
Pennsylvania	H.B. 1509	PUC has authority to approve flexible rates, including negotiated, contract-based tariffs and to use performance based rates. (p. 45)
Rhode Island	96-H 8124 Sub. B	It is in the public interest to establish performance based rate making. To hold overall rate increases to the level of inflation, for the period 1/1/97 to 12/31/98, distribution companies shall implement a PBR plan in accordance with specified provisions, subject to PUC approval. However, rates for low-income customers cannot increase. (p. 3, 33-35)
Massachusetts	H.B.5117	-DTE has authority to promulgate rules and regs to establish and require PBR for each distribution, transmission, and gas company organized and doing business in the Commonwealth. Service quality standards will be established for customer service performance. Each company will file a report with DTE by 3/1 of each year comparing performance during the previous year to DTE's standards. DTE will be able to levy a penalty against any company failing to meet standards up to 2% of revenues for the previous calendar year.
Connecticut	H.B. 5005	The DPUC must investigate performance-based regulation by having each distrib co design a PBR plan and report its findings to the Energy and Technology Committee.
Illinois	H.B. 362	An Electric Utility Property Tax Assessment Task Force will be established. From the 1997 assessment year through the 1999 assessment yea fair cash value for any electric generating plant shall be determined using original cost less depreciation, and depreciation rates shall be equal to those in effect on 11/1/97.

Source: http://www.ncsl.org/programs/esnr/compare.htm
Updated: July, 1998

APPENDIX 3
Comparison of States that have Mandated Retail Competition

	Estimated Population		1994 Gross State Product		1995 Energy Consumption			1995 Energy Generation	
	July 1, 1996	% of Total	Millions $	% of GDP	Millions kWh	% Total	Cents/kWh	Millions kWh	% Total
Arizona	4,428,068	1.7%	89,450	1.4%	48,295	1.6%	7.7	68,967	2.4%
California	31,878,234	12.0%	833,935	12.8%	213,693	7.1%	9.9	121,881	4.2%
Illinois	11,846,544	4.5%	317,166	4.9%	126,387	4.2%	7.7	145,165	5.0%
Maine	1,243,316	0.5%	24,629	0.4%	11,386	0.4%	9.6	2,668	0.1%
Maryland	5,071,604	1.9%	125,565	1.9%	56,539	1.9%	7.1	44,659	1.5%
Massachusetts	6,092,352	2.3%	177,313	2.7%	46,750	1.6%	10.3	26,972	0.9%
Michigan	9,594,350	3.6%	227,368	3.5%	94,863	3.2%	7	92,479	3.2%
Montana	879,372	0.3%	16,046	0.2%	13,567	0.5%	4.6	25,411	0.9%
Nevada	1,602,163	0.6%	41,547	0.6%	20,582	0.7%	6.1	19,997	0.7%
New Hampshire	1,162,481	0.4%	28,066	0.4%	8,914	0.3%	11.8	13,936	0.5%
New Jersey	7,987,933	3.0%	242,171	3.7%	66,693	2.2%	10.5	27,088	0.9%
New York	18,184,774	6.9%	544,749	8.4%	129,995	4.3%	11.1	101,161	3.5%
Oklahoma	3,300,902	1.2%	63,541	1.0%	41,288	1.4%	5.5	47,955	1.6%
Pennsylvania	12,056,112	4.5%	279,897	4.3%	125,605	4.2%	7.9	168,942	5.8%
Rhode Island	990,225	0.4%	22,686	0.3%	6,547	0.2%	10.5	653	0.0%
Vermont	588,654	0.2%	12,641	0.2%	5,109	0.2%	9.5	4,840	0.2%
Virginia	6,675,451	2.5%	170,594	2.6%	84,953	2.8%	6.3	52,727	1.8%
Group	123,582,535	46.6%	3,217,364	49.4%	1,101,166	36.6%	8.6*	965,501	33.0%
ALASKA									
United States	265283783	100.0%	6,518,459	100.0%	3,008,641	100.0%	6.9*	2,923,933	100.0%

* Represents weighted average, by kWh consumed.
Sources: U.S. Census Bureau, EIA, Electric Power Annual 1995
From "Creating Competitive Markets in Electric Energy: A Critical Analysis of H.R. 655," T. Lenard & B. Lips, Electricity Journal, May 1998

Appendix 4

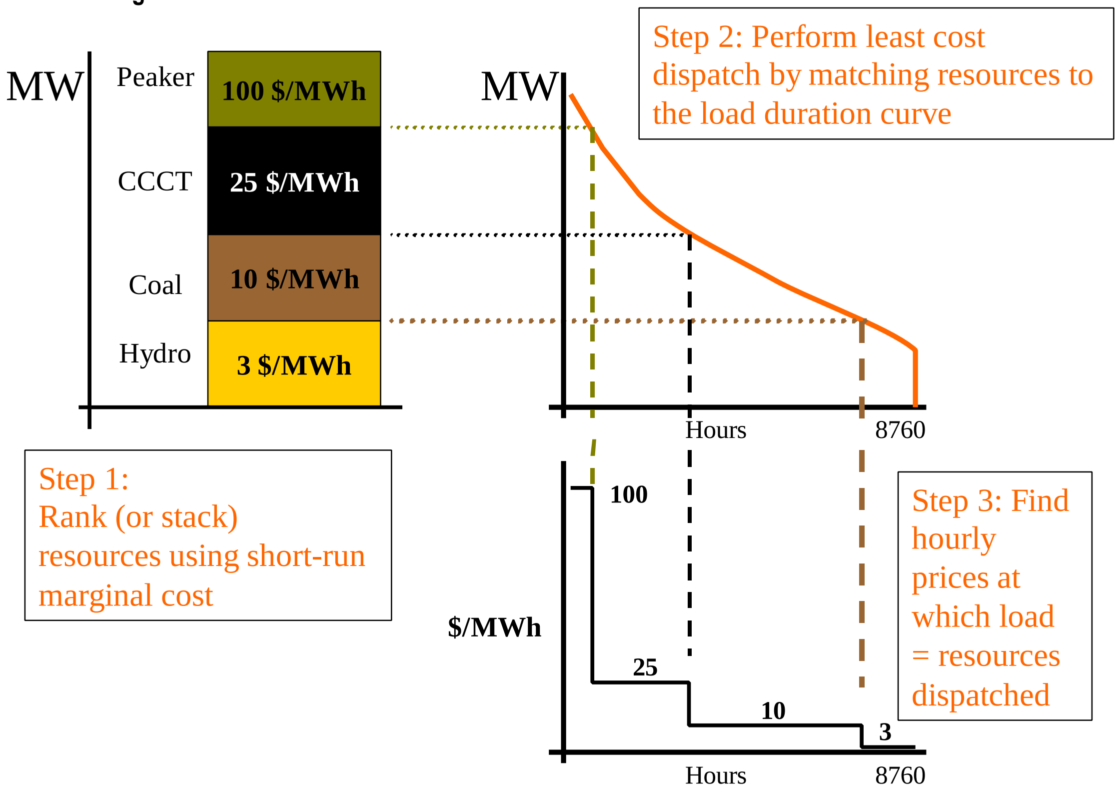
Technical Description of the Stacking Model

The stacking model calculates the operating cost and the market clearing price (MCP) using the least-cost dispatch of plants to serve the hourly demands, subject to transmission transfer limits.

Fundamental Assumptions

- Competition is fierce and sell bids follow short-run marginal cost (SRMC). Under this assumption, each generator bids into a power exchange its entire output at its SRMC that includes fuel and variable O&M. (Some market power scenarios depart from this assumption)
- Because of plant outages and hourly demand fluctuations, the hourly demand is adjusted upwards by 6% to account for operation reserve.
- Hourly demand is price insensitive.
- Bilateral contracts do not affect the dispatch order.
- Easy market entry at "all-in" cost caps the maximum annual MCP. (The surplus capacity in the region negates the need for this assumption)
- All dispatched generators receive the MCP, even if some bids are below the MCP. MCPs exist for intrazonal and export sales.
- Each generator's revenue = MCP x Dispatched output.

FIGURE 1
Basic Stacking Model



The stacking model was modified for this analysis by incorporating the ability to analyze multiple generation and load areas. The multi-area model allows transmission constraints to be modeled between the southern and northern utilities. The multi-area model enhances the standard stacking model analysis by developing separate stacks for each generation zone. Three zones were used for this study, MLP, CEA, and GVEA service territories. The multi-zone stacking works as follows:

1. The load in all three zones is determined for a load duration curve block.[1] The block is derived from the load duration curve and the annual load growth projection.
2. All plants are sorted in ascending order according to bid price. The base case assumes that bid price equals short-run variable costs of operating the plant (fuel and variable O&M)
3. Starting from the lowest bids first, a plant is dispatched subject to two limits

[1] For computational efficiency, the load duration curve consisting of loads for 8760 hours in the year has been summarized down to 74 points. Each point represents between 20 and 500 hours of usage. The magnitude of each point and the number of hours it represents constitute a load duration curve block. For LDC hours 1 to 1000, each block represents 20 hours. For LDC hours 1001 to 2000, each block represents 40 hours, and LDC hours 2001 to 8760 are summarized by 500 hour blocks.

- Total dispatched generation in a zone cannot exceed the zone's sum of native load, operating reserve, and transmission rights.
- Total dispatched generation across all zones must equal the total native demand and operating reserve for the system.

4. Cost of operating each plant are calculated for the load duration curve block, and added to the prior operating costs for the year. Results are tracked by plant ownership.
5. An "in-area" Market Clearing Price (MCP) is calculated for each zone based on the highest cost dispatched plant physically located in the zone. An "export" MCP is also calculated based on the highest cost unit dispatched anywhere in the system. All plants are assumed to serve native load first (that is, a plant serves load in the zone in which it is physically located). Output that exceeds the intrazonal need is assumed to be exported and receives the export MCP. Since the utilities do not own fossil units outside of their zones, it is not necessary to determine which plants serve in-area versus export markets.
6. The model moves to the next load duration block and repeats steps 1 through 5
7. Fixed costs are added after all load duration blocks have been analyzed

Appendix 5

Input Data Assumptions

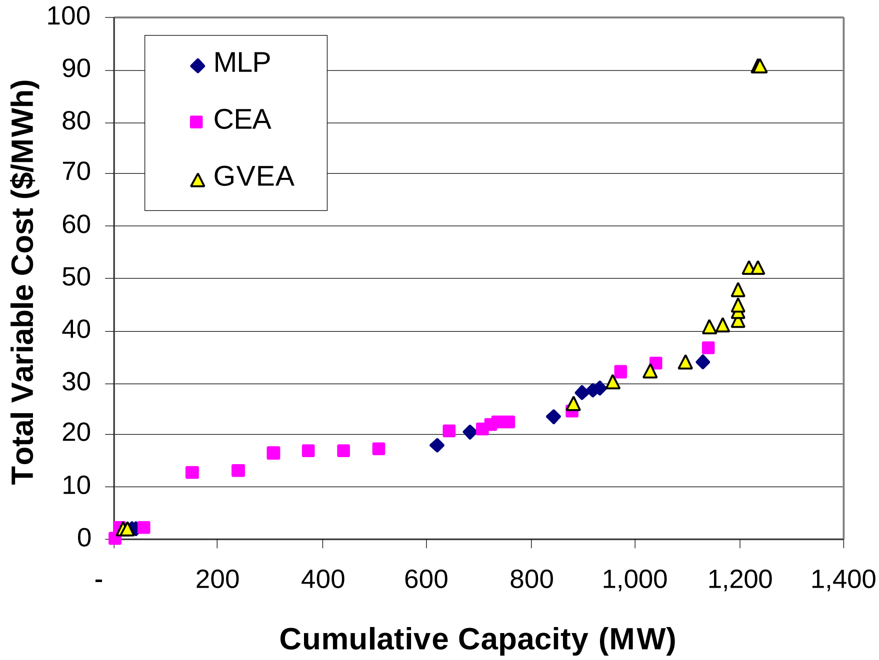
Assumptions and Data Sources

TABLE 1
Plant Information (for 1996)

Plant	Company	1st Yr Online (if after 1996)	Nameplate Capacity (MW)	Maximum Capacity Factor	Adjusted Capacity	Fuel Type	Fuel $/MMBTU	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr)	Variable ($/MWh)
MLP Plant1 Unit 1	MLP		16.8	97%	16.2	Gas	1.86	14,590	27.1	7.66	2
MLP Plant1 Unit 2	MLP		16.8	97%	16.2	Gas	1.86	13,980	26.0	7.66	2
MLP Plant1 Unit 3	MLP		19.5	97%	18.9	Gas	1.86	14,371	26.7	7.66	2
MLP Plant1 Unit 4	MLP		34.1	97%	33.0	Gas	1.86	17,324	32.2	7.66	2
MLP Plant2 Unit 5	MLP		38.4	97%	37.1	Gas	1.86	10,106	18.8	0	2
MLP Plant2 Unit7/6	MLP		109.5	97%	105.9	Gas	1.86	8,527	15.9	7.266	2
MLP Plant2 Unit 8	MLP		87.6	97%	84.7	Gas	1.86	11,557	21.5	7.266	2
Beluga Unit 1	CEA		16.7	93%	15.5	Gas	1.17	16,924	19.8	7.95	2
Beluga Unit 2	CEA		16.7	98%	16.4	Gas	1.17	17,320	20.3	7.95	2
Beluga Unit 3	CEA		66.9	96%	64.2	Gas	1.17	12,288	14.4	7.95	2
Beluga Unit 5	CEA		71	97%	68.9	Gas	1.17	12,537	14.7	7.95	2
Beluga Unit 6	CEA		74	90%	66.6	Gas	1.17	12,743	14.9	7.95	2
Beluga Unit 7	CEA		74	95%	70.3	Gas	1.17	13,172	15.4	7.95	2
Beluga Unit 6-8	CEA		101.5	90%	91.4	Gas	1.17	9,372	11.0	7.95	2
Beluga Unit 7-8	CEA		101.5	90%	91.4	Gas	1.17	9,149	10.7	7.95	2
Bernice Lake 2	CEA		19.3	100%	19.3	Gas	1.38	14,817	20.4	6.5	2
Bernice Lake 3	CEA		28	93%	26.0	Gas	1.38	13,512	18.6	6.5	2
Bernice Lake 4	CEA		28	95%	26.6	Gas	1.38	13,715	18.9	6.5	2
International 1	CEA		15	90%	13.5	Gas	1.98	15,992	31.7	5.75	2
International 2	CEA		15.1	90%	13.6	Gas	1.98	17,384	34.4	5.75	2
International 3	CEA		18.9	89%	16.8	Gas	1.98	15,030	29.8	5.75	2
Soldotna 1	CEA		39	99%	38.6	Gas	1.98	11,401	22.6	3.399	2
Chena 6	GVEA		29	95%	27.6	HAGO	3.4	12,256	41.7	9	0.3
Zehnder EMD 5	GVEA		2.6	99%	2.6	HAGO	3.21	25,679	82.4	8.44497	8.24
Zehnder EMD 6	GVEA		2.6	99%	2.6	HAGO	3.21	25,679	82.4	8.44497	8.24
Zehnder GT 1	GVEA		18	99%	17.8	HAGO	3.21	14,560	46.7	7.84654	5.37
Zehnder GT 2	GVEA		18	99%	17.8	HAGO	3.21	14,560	46.7	7.84654	5.37
North Pole 1	GVEA		56.7	95%	53.9	HAGO	3	9,751	29.3	5.32201	4.8
North Pole 2	GVEA		59.3	92%	54.6	HAGO	3	9,154	27.5	5.32201	4.8
Healy 1	GVEA		25	91%	22.8	Coal	1.36	13,995	19.0	97.49671	11.1961
Healy D 1	GVEA		2.6	95%	2.5	HAGO	3.21	11,451	36.8	23.33465	8.24
Bradley Lake - GVEA	GVEA		15.2	40%	6.0	Hydro	0	1	-	20.6	2.16
Bradley Lake - HEA	GVEA		10.8	43%	4.7	Hydro	0	1	-	20.6	2.16
Bradley Lake - ML&P	MLP		23.3	44%	10.3	Hydro	0	1	-	20	2.16
Ekultna	MLP		21.3	40%	8.6	Hydro	0	1	-	20	2.16
Bradley - Chugach	CEA		40.7	42%	17.3	Hydro	0	1	-	20.6	2.163
Ekultna Chugach	CEA		18.7	37%	7.0	Hydro	0	1	-	20.6	2.16
Cooper Lake 1	CEA		8.6	33%	2.8	Hydro	0	1	-	22.15736	0.206
Cooper Lake 2	CEA		8.6	33%	2.8	Hydro	0	1	-	22.157	0.21
GE 7EA	GVEA	2004	85.4	95%	-	HAGO	3.21	11,721	37.6	4.4	3.03
GE 7EA CC	GVEA	2012	128	95%	-	HAGO	3.21	6,861	22.0	23.38	3.84
GE 6B SC	GVEA	2016	38	95%	-	HAGO	3.21	12,242	39.3	7.36	4.41
GVEA HCCP	GVEA	1999	53	95%	-	HAGO	3.21	11,804	37.9	63.8	10
Aurora Chena	GVEA		29	47%	27.6	HAGO	3.21	12,256	39.3	3.399	2

Plant characteristics from BVI study Appendix C

FIGURE 1
Variable Costs (Fuel and O&M) of Utility Generation



As shown in Figure 1, review of the heat rates confirms that the engineering performance of the MLP and CEA units are not drastically different. The significant advantage of CEA plants over the MLP plants shown in Figure 2 is due to the gas prices forecasted for each utility.

FIGURE 2
Natural Gas Generator Heat Rate Supply Curve ($1996)

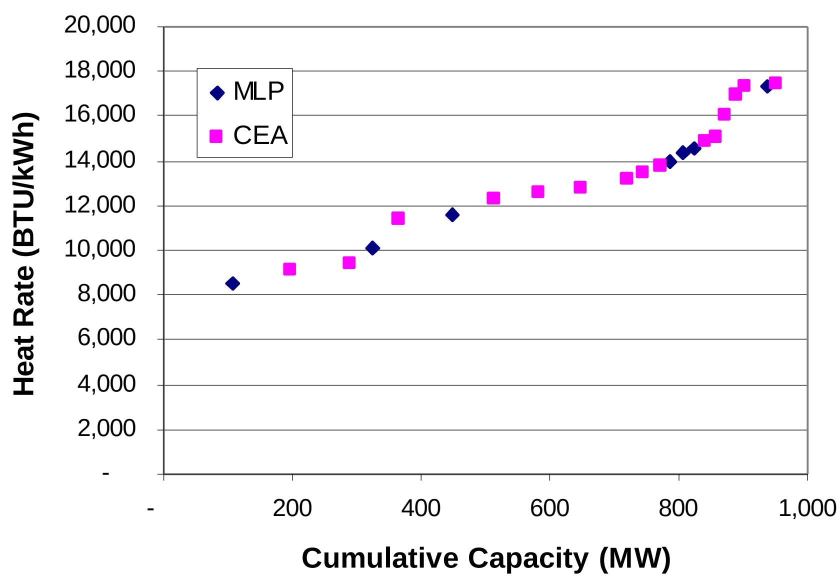


TABLE 2
Fuel Costs by Year and Plant ($/MMBTU)

Utility	ML&P	Chugach			HEA	GVEA			
Plant	All	Beluga	Bernice	Int'l	Soldotna	Healy	North	Zehnder	Chena
Unit(s)		1 to 8	2 to 4	1 to 3	1	1	Pole		6
Fuel	NG	NG	NG	NG	NG	Coal	Hago	Hago	Hago
1996	1.86	1.17	1.38	1.98	1.98	1.36	3	3.21	3.4
1997	1.74	1.46	1.5	2.25	2.25	1.39	3.09	3.31	3.4
1998	1.97	1.69	1.7	2.05	2.05	1.02	3.18	3.41	3.5
1999	2.01	1.73	1.75	2.1	2.1	0.94	3.28	3.51	3.61
2000	2.06	1.78	1.8	2.15	2.15	0.97	3.38	3.62	3.72
2001	2.12	1.84	1.85	2.2	2.2	0.99	3.48	3.73	3.83
2002	2.16	1.88	1.9	2.25	2.25	1.05	3.58	3.84	3.94
2003	2.22	1.94	1.95	2.3	2.3	1.07	3.69	3.95	4.06
2004	2.27	1.99	2	2.35	2.35	1.09	3.8	4.07	4.18
2005	2.33	2.05	2.06	2.41	2.41	1.11	3.91	4.19	4.31
2006	2.39	2.11	2.12	2.47	2.47	1.13	4.03	4.32	4.44
2007	2.44	2.16	2.18	2.53	2.53	1.16	4.15	4.45	4.57
2008	2.5	2.22	2.24	2.59	2.59	1.18	4.28	4.58	4.71
2009	2.57	2.29	2.3	2.65	2.65	1.2	4.41	4.72	4.85
2010	2.63	2.35	2.37	2.72	2.72	1.22	4.54	4.86	4.99
2011	2.7	2.42	2.44	2.79	2.79	1.25	4.67	5.01	5.14
2012	2.77	2.49	2.5	2.85	2.85	1.27	4.81	5.16	5.3
2013	2.84	2.56	2.57	2.92	2.92	1.29	4.96	5.31	5.46
2014	2.91	2.63	2.65	3	3	1.32	5.11	5.47	5.62
2015	2.98	2.7	2.72	3.07	3.07	1.34	5.26	5.64	5.79
2016	3.06	2.78	2.8	3.15	3.15	1.37	5.42	5.8	5.96

Source: BVI Table 3-3. No value was shown for Chena 6 HAGO in 1996, so the 1997 value was replicated.

Load Growth

TABLE 3
Expected Zonal and System Peak Loads (MW)[1]

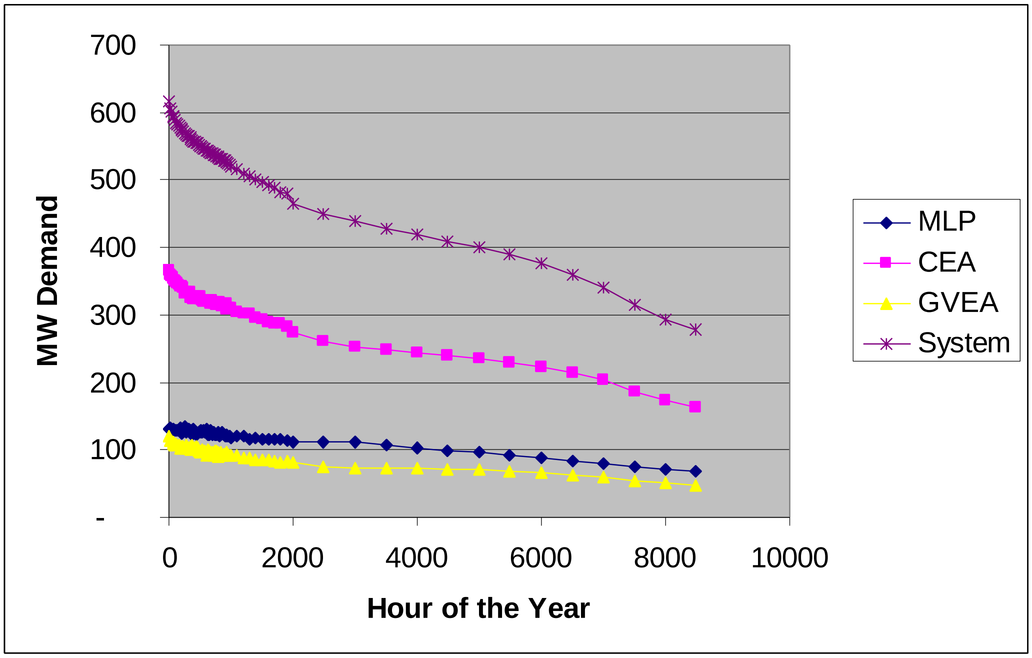
	Data from BVI Table 3-1.						System Totals
Year	ML&P	Chugach	GVEA	HEA	MEA	Total	From BVI Table 5-9
1996	151	381	127	73	94	659	634.17
1997	152	380	167	73	98	698	672
1998	154	384	196	74	100	733	707
1999	156	389	201	75	101	745	718
2000	158	394	203	76	103	755	728
2001	160	399	208	77	104	768	740
2002	163	405	214	78	106	782	753
2003	166	413	220	79	107	799	770
2004	168	420	228	80	109	816	780
2005	170	424	232	81	111	826	797
2006	173	426	236	81	112	835	805
2007	175	432	241	82	114	847	817
2008	177	439	245	83	116	862	831
2009	179	446	250	85	117	876	845
2010	182	453	255	86	118	890	859
2011	184	461	260	87	119	905	874
2012	187	470	266	89	120	922	890
2013	189	478	271	91	122	938	906
2014	192	487	276	92	123	955	923
2015	195	497	282	94	124	974	933
2016	197	506	288	96	125	991	957
2017	200	514	296	97	127	1,009	975
2018	203	521	304	98	129	1,028	994
2019	205	529	313	100	130	1,048	1,013
2020	208	537	322	101	132	1,068	1,032
2021	211	546	332	102	134	1,089	1,052
2022	214	554	341	104	136	1,109	1,072
2023	217	562	351	105	137	1,131	1,093
2024	220	571	362	107	139	1,153	1,114
2025	223	580	372	108	141	1,175	1,135
2026	226	588	383	110	143	1,198	1,157
2027	229	597	394	111	145	1,221	1,180
AAGR	1.39	1.52	2.91	1.40	1.32		
Chugach's peak demand includes AEG&T, HEA, MEA, and SES.							
AAGR = Annual Average Growth Rate over 1997 - 2016.							

[1] Total load is the total, noncoincident peak load of the railbelt utilities. System total load is the coincident peak load of the rail belt utilities, as reported in the BVI study. Load forecast for the period 1996 – 2016 is replicated from the BVI data. Load forecasted between 2017 and 2027 is escalated at the annual average load growth rates from the BVI data, and as shown in the row title AAGR.

Hourly Load Information from Alaska PUC

The hourly loads were converted to load duration curves. For computational efficiency, the first 1,000 hours of the LDC are represented by 20 hour averages. Hours 1,001 through 2,000 are represented by 40 hour averages, and the remainder of the LDC uses 500 hour averages.

FIGURE 3
Load Duration Curves



Hourly loads (annual load shapes) are assumed to escalate linearly each year at the same rate as the peak demand forecast (BVI Table 3-1).

Detailed Modeling Inputs (Appendix 6)

List of Tables

List of Tables continued

Scenario Summary

Table 1: Scenario Control Sheet

Controls for Stacking Model	Base Case	System	Independent dispatch	Fuel Costs the Same	CEA 20%, Contract transmission	CEA 40%, Contract transmission	Unlimited Transmission	CEA 10% and Unlimited Transmission	CEA 20% and Unlimited Transmission	Equal Split on T	CEA + 20%, Equal Split on T	CEA + 40%, Equal Split on T	No New Gen	Fuel Costs the Same, Equal T Split	CEA 40%, 70MW MLP	Withdraw Beluga 3	Withdraw Beluga 6-8	Additional 2 % Growth	Minus 1.5% Growth
Scenario Number		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	18	19
Year being analyzed:																			
Starting Year	1996																		
Model Scenario in Use:	4																		
Start Year	1996																		
End Year	2017																		
System transmission constraint set	0		1				2	2	2	3	3	3		3	4				
Plant Capacities																			
Beluga 3 (MW)	66.90															0			
Beluga Unit 6-8 (MW)	101.5																0		
Set Fuel Costs Equal	FALSE			TRUE										TRUE					
CEA Company strategic bidding (% Premium)	0%				20%	40%		10%	20%		20%	40%			40%				
GE 7EA	2004												2018						
GE 7EA CC	2012												2018						
GE 6B SC	2016												2018						
GVEA HCCP	1999												2018						
Growth Rate Adjustment (%/yr)	0%																	2%	-1.50%

The Scenario Control Sheet summarizes the variation in input values for the numerous Stacking model cases run as part of this Alaska Analysis.
If an entry is blank, the values from the Base Case column are used for the scenario. A subset of these scenarios were also run for the case where a 100MW IPP locates in GVEA's service territory in 2002.Plant Information (1996)

Table 2: Base Case Plant Information

System: Scenario - 1

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
										0%
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 3: Base case continued

System: Scenario - 1

	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 4: Independent Dispatch

Independent: Scenario - 2

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 5: Independent Dispatch, continued

Independent: Scenario - 2	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 6: Equalized Fuel Costs

Fuel Costs the Same: Scenario - 3

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.17	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.17	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.17	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.17	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.17	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.17	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.17	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.17	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.17	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.17	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.17	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.17	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.17	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.17	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 7: Equalized Fuel Costs, continued

Fuel Costs the Same: Scenario - 3

	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	17	7.66	2.00	3.0%	3.0%	$ 129	2.0000	19.07	19.07
MLP Plant1 Unit 2	13,980	16	7.66	2.00	3.0%	3.0%	$ 129	2.0000	18.36	18.36
MLP Plant1 Unit 3	14,371	17	7.66	2.00	3.0%	3.0%	$ 149	2.0000	18.81	18.81
MLP Plant1 Unit 4	17,324	20	7.66	2.00	3.0%	3.0%	$ 261	2.0000	22.27	22.27
MLP Plant2 Unit 5	10,106	12	0.00	2.00	3.0%	3.0%	$ -	2.0000	13.82	13.82
MLP Plant2 Unit7/6	8,527	10	7.27	2.00	3.0%	3.0%	$ 796	2.0000	11.98	11.98
MLP Plant2 Unit 8	11,557	14	7.27	2.00	3.0%	3.0%	$ 637	2.0000	15.52	15.52
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	17	6.5	2.00	3.0%	3.0%	$ 125	2.0000	19.34	19.34
Bernice Lake 3	13,512	16	6.5	2.00	3.0%	3.0%	$ 182	2.0000	17.81	17.81
Bernice Lake 4	13,715	16	6.5	2.00	3.0%	3.0%	$ 182	2.0000	18.05	18.05
International 1	15,992	19	5.8	2.00	3.0%	3.0%	$ 86	2.0000	20.71	20.71
International 2	17,384	20	5.8	2.00	3.0%	3.0%	$ 87	2.0000	22.34	22.34
International 3	15,030	18	5.8	2.00	3.0%	3.0%	$ 109	2.0000	19.59	19.59
Soldotna 1	11,401	13	3.4	2.00	3.0%	3.0%	$ 133	2.0000	15.34	15.34
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 8: CEA Bids 20% above Dispatch Cost - Contract Transmission

CEA 20%, Contract transmission: Scenario - 4 | 20%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	4
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	4
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	3
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	3
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	3
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	3
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	4
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	4
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	4
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	6
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	5
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 9: CEA Bids 20% above Dispatch Cost - Contract Transmission

CEA 20%, Contract transmission: Scenario - 4					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	26.16
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	26.72
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	19.65
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	20.00
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	20.29
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	20.89
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	15.56
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	15.25
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	26.94
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	24.78
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	25.11
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	40.40
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	43.70
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	38.11
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	29.49
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 10: CEA Bids 40% above Dispatch Cost - Contract Transmission

CEA 40%, Contract transmission: Scenario - 5

40%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	9
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	9
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	7
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	7
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	7
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	7
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	9
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	8
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	8
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	13
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	15
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	13
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	10
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA	2018	40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 11: CEA Bids 40% above Dispatch Cost - Contract Transmission, continued

CEA 40%, Contract transmission: Scenario - 5					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	*7.66*	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	*7.66*	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	*7.66*	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	*7.66*	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	*0.00*	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	*7.27*	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	*7.27*	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	30.52
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	31.17
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	22.93
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	23.34
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	23.67
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	24.38
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	18.15
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	17.79
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	31.43
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	28.91
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	29.30
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	47.13
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	50.99
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	44.46
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	34.40
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 12: Unlimited Transmission Capacity

Unlimited Transmission: Scenario - 6

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 13: Unlimited Transmission Capacity, continued

Unlimited Transmission: Scenario - 6	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 14: CEA bids 10% above Dispatch Cost w/ Unlimited Transmission

CEA 10% and Unlimited Transmission: Scenario - 7

10%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	2
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	2
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	2
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	2
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	2
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	2
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	1
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	1
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	2
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	2
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	2
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	3
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	4
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	3
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	2
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 15: CEA bids 10% above Dispatch Cost w/ Unlimited Transmission, continued

CEA 10% and Unlimited Transmission: Scenario - 7					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	23.98
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	24.49
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	18.01
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	18.34
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	18.60
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	19.15
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	14.26
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	13.97
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	24.69
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	22.71
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	23.02
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	37.03
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	40.06
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	34.94
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	27.03
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 16: CEA bids 20% above Dispatch Cost w/ Unlimited Transmission

CEA 20% and Unlimited Transmission: Scenario - 8

20%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	4
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	4
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	3
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	3
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	3
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	3
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	4
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	4
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	4
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	6
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	5
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 17: CEA bids 20% above Dispatch Cost w/ Unlimited Transmission, continued

CEA 20% and Unlimited Transmission: Scenario - 8					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	26.16
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	26.72
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	19.65
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	20.00
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	20.29
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	20.89
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	15.56
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	15.25
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	26.94
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	24.78
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	25.11
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	40.40
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	43.70
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	38.11
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	29.49
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 18: Equal Split on Transmission Capacity between MLP and CEA

Equal Split on T: Scenario - 9

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 19: Equal Split on Transmission Capacity between MLP and CEA, continued

Equal Split on T: Scenario - 9					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 20: CEA bids 20% above Dispatch Cost, w/equal Split on Transmission Capacity

CEA + 20%, Equal Split on T: Scenario - 10 | 20%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	4
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	4
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	3
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	3
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	3
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	3
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	3
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	4
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	4
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	4
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	7
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	6
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	5
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 21: CEA bids 20% above Dispatch Cost, w/equal Split on Transmission Capacity, continued

CEA + 20%, Equal Split on T: Scenario - 10	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	26.16
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	26.72
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	19.65
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	20.00
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	20.29
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	20.89
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	15.56
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	15.25
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	26.94
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	24.78
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	25.11
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	40.40
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	43.70
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	38.11
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	29.49
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 22: CEA bids 40% above Dispatch Cost, w/equal Split on Transmission Capacity

CEA + 40%, Equal Split on T: Scenario - 11

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
										40%
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	9
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	9
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	7
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	7
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	7
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	7
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	9
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	8
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	8
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	13
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	15
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	13
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	10
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA	2018	40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 23: CEA bids 40% above Dispatch Cost, w/equal Split on Transmission Capacity, continued

CEA + 40%, Equal Split on T: Scenario - 11					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	30.52
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	31.17
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	22.93
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	23.34
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	23.67
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	24.38
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	18.15
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	17.79
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	31.43
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	28.91
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	29.30
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	47.13
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	50.99
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	44.46
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	34.40
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 24: No New Generation

No New Gen: Scenario - 12 — 0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2018	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2018	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2018	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	2018	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 25: No New Generation, continued

No New Gen: Scenario - 12	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 26: Fuel Costs the Same w/ Equal Split of Transmission Between MLP and CEA

Fuel Costs the Same, Equal T Split: Scenario - 13 | 0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.17	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.17	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.17	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.17	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.17	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.17	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.17	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.17	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.17	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.17	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.17	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.17	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.17	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.17	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 27: Fuel Costs the Same w/ Equal Split of Transmission Between MLP and CEA, continued

Fuel Costs the Same, Equal T Split: Scenario - 13	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	17	7.66	2.00	3.0%	3.0%	$ 129	2.0000	19.07	19.07
MLP Plant1 Unit 2	13,980	16	7.66	2.00	3.0%	3.0%	$ 129	2.0000	18.36	18.36
MLP Plant1 Unit 3	14,371	17	7.66	2.00	3.0%	3.0%	$ 149	2.0000	18.81	18.81
MLP Plant1 Unit 4	17,324	20	7.66	2.00	3.0%	3.0%	$ 261	2.0000	22.27	22.27
MLP Plant2 Unit 5	10,106	12	0.00	2.00	3.0%	3.0%	$ -	2.0000	13.82	13.82
MLP Plant2 Unit7/6	8,527	10	7.27	2.00	3.0%	3.0%	$ 796	2.0000	11.98	11.98
MLP Plant2 Unit 8	11,557	14	7.27	2.00	3.0%	3.0%	$ 637	2.0000	15.52	15.52
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	17	6.5	2.00	3.0%	3.0%	$ 125	2.0000	19.34	19.34
Bernice Lake 3	13,512	16	6.5	2.00	3.0%	3.0%	$ 182	2.0000	17.81	17.81
Bernice Lake 4	13,715	16	6.5	2.00	3.0%	3.0%	$ 182	2.0000	18.05	18.05
International 1	15,992	19	5.8	2.00	3.0%	3.0%	$ 86	2.0000	20.71	20.71
International 2	17,384	20	5.8	2.00	3.0%	3.0%	$ 87	2.0000	22.34	22.34
International 3	15,030	18	5.8	2.00	3.0%	3.0%	$ 109	2.0000	19.59	19.59
Soldotna 1	11,401	13	3.4	2.00	3.0%	3.0%	$ 133	2.0000	15.34	15.34
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 28: CEA bids 40% above Dispatch Costs w/ 70MW Transmission Capacity for MLP

CEA 40%, 70MW MLP: Scenario - 14

40%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	9
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	9
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	7
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	7
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	7
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	7
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	5
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	9
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	8
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	8
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	13
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	15
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	13
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	10
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 29: CEA bids 40% above Dispatch Costs w/ 70MW Transmission Capacity for MLP, continued

CEA 40%, 70MW MLP: Scenario - 14	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	30.52
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	31.17
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	22.93
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	23.34
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	23.67
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	24.38
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	18.15
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	17.79
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	31.43
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	28.91
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	29.30
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	47.13
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	50.99
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	44.46
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	34.40
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 30: Withdraw Beluga 3

Withdraw Beluga 3: Scenario - 15

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		-	96%	0	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA	2018	40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 31: Withdraw Beluga 3, continued

Withdraw Beluga 3: Scenario - 15					O&M Inflation					
	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	Fixed	Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ -	9,999.0000	10,013.38	10,013.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 32: Withdraw Beluga 6-8

Withdraw Beluga 6-8: Scenario - 16

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		-	90%	0	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 33: Withdraw Beluga 6-8, continued

Withdraw Beluga 6-8: Scenario - 16	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ -	9,999.0000	10,009.97	10,009.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 34: Additional 2% Annual Growth

Additional 2 % Growth: Scenario - 18

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA	2018	40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 35: Additional 2% Annual Growth, continued

Additional 2 % Growth: Scenario - 18	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

Table 36: 1.5% less Annual Growth

Minus 1.5% Growth: Scenario - 19

0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	1.86	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	1.86	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	1.86	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	1.86	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	1.86	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	1.86	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.17	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.17	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.17	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.17	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.17	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.17	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.17	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.38	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.38	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.38	0
International 1	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 2	CEA	Gas	4	CEA		15	0.90	14	1.98	0
International 3	CEA	Gas	4	CEA		19	0.89	17	1.98	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	1.98	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.4	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.21	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.21	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.36	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.21	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.21	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.21	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.21	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	0	3.21	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.21	
Merchant Plant	Ind	gas	2	GVEA	2018	100	100%	0	1.17	

Table 37: 1.5% less Annual Growth, continued

Minus 1.5% Growth: Scenario - 19	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	27	7.66	2.00	3.0%	3.0%	$ 129	2.0000	29.14	29.14
MLP Plant1 Unit 2	13,980	26	7.66	2.00	3.0%	3.0%	$ 129	2.0000	28.00	28.00
MLP Plant1 Unit 3	14,371	27	7.66	2.00	3.0%	3.0%	$ 149	2.0000	28.73	28.73
MLP Plant1 Unit 4	17,324	32	7.66	2.00	3.0%	3.0%	$ 261	2.0000	34.22	34.22
MLP Plant2 Unit 5	10,106	19	0.00	2.00	3.0%	3.0%	$ -	2.0000	20.80	20.80
MLP Plant2 Unit7/6	8,527	16	7.27	2.00	3.0%	3.0%	$ 796	2.0000	17.86	17.86
MLP Plant2 Unit 8	11,557	21	7.27	2.00	3.0%	3.0%	$ 637	2.0000	23.50	23.50
Beluga Unit 1	16,924	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	21.80	21.80
Beluga Unit 2	17,320	20	8.0	2.00	3.0%	3.0%	$ 133	2.0000	22.26	22.26
Beluga Unit 3	12,288	14	8.0	2.00	3.0%	3.0%	$ 532	2.0000	16.38	16.38
Beluga Unit 5	12,537	15	8.0	2.00	3.0%	3.0%	$ 564	2.0000	16.67	16.67
Beluga Unit 6	12,743	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	16.91	16.91
Beluga Unit 7	13,172	15	8.0	2.00	3.0%	3.0%	$ 588	2.0000	17.41	17.41
Beluga Unit 6-8	9,372	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.97	12.97
Beluga Unit 7-8	9,149	11	8.0	2.00	3.0%	3.0%	$ 807	2.0000	12.70	12.70
Bernice Lake 2	14,817	20	6.5	2.00	3.0%	3.0%	$ 125	2.0000	22.45	22.45
Bernice Lake 3	13,512	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.65	20.65
Bernice Lake 4	13,715	19	6.5	2.00	3.0%	3.0%	$ 182	2.0000	20.93	20.93
International 1	15,992	32	5.8	2.00	3.0%	3.0%	$ 86	2.0000	33.66	33.66
International 2	17,384	34	5.8	2.00	3.0%	3.0%	$ 87	2.0000	36.42	36.42
International 3	15,030	30	5.8	2.00	3.0%	3.0%	$ 109	2.0000	31.76	31.76
Soldotna 1	11,401	23	3.4	2.00	3.0%	3.0%	$ 133	2.0000	24.57	24.57
Chena 6	12,256	42	9	0.3	3.0%	3.0%	$ 261	0.3000	41.97	41.97
Zehnder EMD 5	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder EMD 6	25,679	82	8	8.2	3.0%	3.0%	$ 22	8.2400	90.67	90.67
Zehnder GT 1	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
Zehnder GT 2	14,560	47	8	5.4	3.0%	3.0%	$ 141	5.3700	52.11	52.11
North Pole 1	9,751	29	5	4.8	3.0%	3.0%	$ 302	4.8000	34.05	34.05
North Pole 2	9,154	27	5	4.8	3.0%	3.0%	$ 316	4.8000	32.26	32.26
Healy 1	13,995	19	97	11.2	3.0%	3.0%	$ 2,437	11.1961	30.23	30.23
Healy D 1	11,451	37	23	8.2	3.0%	3.0%	$ 61	8.2400	45.00	45.00
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 313	2.1600	2.16	2.16
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 222	2.1600	2.16	2.16
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 466	2.1600	2.16	2.16
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 426	2.1600	2.16	2.16
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 838	2.1630	2.16	2.16
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 385	2.1600	2.16	2.16
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2060	0.21	0.21
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 191	0.2100	0.21	0.21
GE 7EA	11,721	38	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,036.62	10,036.62
GE 7EA CC	6861	22	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,021.02	10,021.02
GE 6B SC	12242	39	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,038.30	10,038.30
GVEA HCCP	11804	38	63.8	10.0	3.0%	3.0%	$ -	9,999.0000	10,036.89	10,036.89
Aurora Chena	12,256	39	3.4	2.0	3.0%	3.0%	$ 99	2.0000	41.34	41.34
Merchant Plant	6,861	8	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,007.03	10,007.03

IPP Merchant Plant in 2002

Table 38: Addition of Merchant Plant in 2002

(Note that this table is for the year 2002 to show values for the merchant plant)

Add IPP: Scenario - 20 0%

Plant	Company	Fuel Type	Fuel Cost Index	Area	First year online	Raw Capacity (MW)	Maximum Capacity Factor	Capacity Adj for Ownership Availability & Installation	Fuel $/MBTU	CEA Bid Premium
MLP Plant1 Unit 1	MLP	Gas	1	MLP		16.8	97%	16	2.16	
MLP Plant1 Unit 2	MLP	Gas	1	MLP		16.8	97%	16	2.16	
MLP Plant1 Unit 3	MLP	Gas	1	MLP		19.5	97%	19	2.16	
MLP Plant1 Unit 4	MLP	Gas	1	MLP		34.1	97%	33	2.16	
MLP Plant2 Unit 5	MLP	Gas	1	MLP		38.4	97%	37	2.16	
MLP Plant2 Unit7/6	MLP	Gas	1	MLP		109.5	97%	106	2.16	
MLP Plant2 Unit 8	MLP	Gas	1	MLP		87.6	97%	85	2.16	
Beluga Unit 1	CEA	Gas	2	CEA		16.7	93%	16	1.88	0
Beluga Unit 2	CEA	Gas	2	CEA		16.7	98%	16	1.88	0
Beluga Unit 3	CEA	Gas	2	CEA		66.90	96%	64	1.88	0
Beluga Unit 5	CEA	Gas	2	CEA		71	97%	69	1.88	0
Beluga Unit 6	CEA	Gas	2	CEA		74	90%	67	1.88	0
Beluga Unit 7	CEA	Gas	2	CEA		74	95%	70	1.88	0
Beluga Unit 6-8	CEA	Gas	2	CEA		101.50	90%	91	1.88	0
Beluga Unit 7-8	CEA	Gas	2	CEA		101.50	90%	91	1.88	0
Bernice Lake 2	CEA	Gas	3	CEA		19	1.00	19	1.9	0
Bernice Lake 3	CEA	Gas	3	CEA		28	0.93	26	1.9	0
Bernice Lake 4	CEA	Gas	3	CEA		28	0.95	27	1.9	0
International 1	CEA	Gas	4	CEA		15	0.90	14	2.25	0
International 2	CEA	Gas	4	CEA		15	0.90	14	2.25	0
International 3	CEA	Gas	4	CEA		19	0.89	17	2.25	0
Soldotna 1	CEA	Gas	5	CEA		39	0.99	39	2.25	0
Chena 6	GVEA	HAGO	9	GVEA		29	0.95	28	3.94	
Zehnder EMD 5	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.84	
Zehnder EMD 6	GVEA	HAGO	8	GVEA		2.6	0.99	3	3.84	
Zehnder GT 1	GVEA	HAGO	8	GVEA		18	0.99	18	3.84	
Zehnder GT 2	GVEA	HAGO	8	GVEA		18	0.99	18	3.84	
North Pole 1	GVEA	HAGO	7	GVEA		56.7	0.95	54	3.58	
North Pole 2	GVEA	HAGO	7	GVEA		59.3	0.92	55	3.58	
Healy 1	GVEA	Coal	6	GVEA		25	0.91	23	1.05	
Healy D 1	GVEA	HAGO	8	GVEA		2.6	0.95	2	3.84	
Bradley Lake - GVEA	GVEA	Hydro		GVEA		15.2	0.397245254	6	0.0000	
Bradley Lake - HEA	GVEA	Hydro		GVEA		10.8	0.434836377	5	0.0000	
Bradley Lake - ML&P	MLP	Hydro		MLP		23.3	0.442574519	10	0.0000	
Ekultna	MLP	Hydro		MLP		21.3	0.401660343	9	0.0000	
Bradley - Chugach	CEA	Hydro		CEA		40.70	0.424320959	17	0.0000	
Ekultna Chugach	CEA	Hydro		CEA		18.70	0.374325446	7	0.0000	
Cooper Lake 1	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
Cooper Lake 2	CEA	Hydro		CEA		8.60	0.325607943	3	0.0000	
GE 7EA	GVEA	HAGO	8	GVEA	2004	85	0.95	0	3.84	
GE 7EA CC	GVEA	HAGO	8	GVEA	2012	128	0.95	0	3.84	
GE 6B SC	GVEA	HAGO	8	GVEA	2016	38	0.95	0	3.84	
GVEA HCCP	GVEA	HAGO	8	GVEA	1999	53	0.95	50	3.84	
Aurora Chena	GVEA	HAGO	8	GVEA	0	29	0.95	28	3.84	
Merchant Plant	Ind	gas	2	GVEA	2002	100	100%	100	1.88	

Note: Numerous scenarios were run with the merchant plant built in the year 2002. Those input files will exactly match their conterparts above, with the sole exception of the year 2002 replacing the year 2018 for the year the Merchant Plant is on line.

Table 39: Merchant plant in 2002, continued.

Add IPP: Scenario - 20	Heat Rate (BTU/kWh)	Fuel Costs ($/MWh)	Fixed ($/kW-yr) - Cnstnt $'s	Variable ($/MWh) Cnstnt $'s	O&M Inflation Fixed	O&M Inflation Variable	Fixed Costs (k$)	Inflated Variable O&M Cost ($/MWh)	Total Dispatch Cost ($/MWh)	Bid Cost for Ranking ($/MWh)
MLP Plant1 Unit 1	14,590	32	7.66	2.00	3.0%	3.0%	$ 154	2.3881	33.90	33.90
MLP Plant1 Unit 2	13,980	30	7.66	2.00	3.0%	3.0%	$ 154	2.3881	32.58	32.58
MLP Plant1 Unit 3	14,371	31	7.66	2.00	3.0%	3.0%	$ 178	2.3881	33.43	33.43
MLP Plant1 Unit 4	17,324	37	7.66	2.00	3.0%	3.0%	$ 312	2.3881	39.81	39.81
MLP Plant2 Unit 5	10,106	22	0.00	2.00	3.0%	3.0%	$ -	2.3881	24.22	24.22
MLP Plant2 Unit7/6	8,527	18	7.27	2.00	3.0%	3.0%	$ 950	2.3881	20.81	20.81
MLP Plant2 Unit 8	11,557	25	7.27	2.00	3.0%	3.0%	$ 760	2.3881	27.35	27.35
Beluga Unit 1	16,924	32	8.0	2.00	3.0%	3.0%	$ 159	2.3881	34.21	34.21
Beluga Unit 2	17,320	33	8.0	2.00	3.0%	3.0%	$ 159	2.3881	34.95	34.95
Beluga Unit 3	12,288	23	8.0	2.00	3.0%	3.0%	$ 635	2.3881	25.49	25.49
Beluga Unit 5	12,537	24	8.0	2.00	3.0%	3.0%	$ 674	2.3881	25.96	25.96
Beluga Unit 6	12,743	24	8.0	2.00	3.0%	3.0%	$ 702	2.3881	26.34	26.34
Beluga Unit 7	13,172	25	8.0	2.00	3.0%	3.0%	$ 702	2.3881	27.15	27.15
Beluga Unit 6-8	9,372	18	8.0	2.00	3.0%	3.0%	$ 964	2.3881	20.01	20.01
Beluga Unit 7-8	9,149	17	8.0	2.00	3.0%	3.0%	$ 964	2.3881	19.59	19.59
Bernice Lake 2	14,817	28	6.5	2.00	3.0%	3.0%	$ 150	2.3881	30.54	30.54
Bernice Lake 3	13,512	26	6.5	2.00	3.0%	3.0%	$ 217	2.3881	28.06	28.06
Bernice Lake 4	13,715	26	6.5	2.00	3.0%	3.0%	$ 217	2.3881	28.45	28.45
International 1	15,992	36	5.8	2.00	3.0%	3.0%	$ 103	2.3881	38.37	38.37
International 2	17,384	39	5.8	2.00	3.0%	3.0%	$ 104	2.3881	41.50	41.50
International 3	15,030	34	5.8	2.00	3.0%	3.0%	$ 130	2.3881	36.21	36.21
Soldotna 1	11,401	26	3.4	2.00	3.0%	3.0%	$ 158	2.3881	28.04	28.04
Chena 6	12,256	48	9	0.3	3.0%	3.0%	$ 312	0.3582	48.65	48.65
Zehnder EMD 5	25,679	99	8	8.2	3.0%	3.0%	$ 26	9.8390	108.45	108.45
Zehnder EMD 6	25,679	99	8	8.2	3.0%	3.0%	$ 26	9.8390	108.45	108.45
Zehnder GT 1	14,560	56	8	5.4	3.0%	3.0%	$ 169	6.4121	62.32	62.32
Zehnder GT 2	14,560	56	8	5.4	3.0%	3.0%	$ 169	6.4121	62.32	62.32
North Pole 1	9,751	35	5	4.8	3.0%	3.0%	$ 360	5.7315	40.64	40.64
North Pole 2	9,154	33	5	4.8	3.0%	3.0%	$ 377	5.7315	38.50	38.50
Healy 1	13,995	15	97	11.2	3.0%	3.0%	$ 2,910	13.3687	28.06	28.06
Healy D 1	11,451	44	23	8.2	3.0%	3.0%	$ 72	9.8390	53.81	53.81
Bradley Lake - GVEA	1	0	20.6	2.2	3.0%	3.0%	$ 374	2.5792	2.58	2.58
Bradley Lake - HEA	1	0	20.6	2.2	3.0%	3.0%	$ 266	2.5792	2.58	2.58
Bradley Lake - ML&P	1	0	20.0	2.2	3.0%	3.0%	$ 556	2.5792	2.58	2.58
Ekultna	1	0	20.0	2.2	3.0%	3.0%	$ 509	2.5792	2.58	2.58
Bradley - Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 1,001	2.5827	2.58	2.58
Ekultna Chugach	1	0	20.6	2.2	3.0%	3.0%	$ 460	2.5792	2.58	2.58
Cooper Lake 1	1	0	22.2	0.2	3.0%	3.0%	$ 228	0.2460	0.25	0.25
Cooper Lake 2	1	0	22.2	0.2	3.0%	3.0%	$ 228	0.2508	0.25	0.25
GE 7EA	11,721	45	4.4	3.0	3.0%	3.0%	$ -	9,999.0000	10,044.01	10,044.01
GE 7EA CC	6861	26	23.4	3.8	3.0%	3.0%	$ -	9,999.0000	10,025.35	10,025.35
GE 6B SC	12242	47	7.4	4.4	3.0%	3.0%	$ -	9,999.0000	10,046.01	10,046.01
GVEA HCCP	11804	45	63.8	10.0	3.0%	3.0%	$ 4,038	11.9405	57.27	57.27
Aurora Chena	12,256	47	3.4	2.0	3.0%	3.0%	$ 118	2.3881	49.45	49.45
Merchant Plant	6,861	13	23.4	3.8	3.0%	3.0%	$ 2,792	4.5852	17.48	17.48

Load Growth

Table 40: Base Case Load Growth (Scenarios 1 through 17)

Spinning Reserve Margin:	6%

Data from BVI Table 3-1. Expected Peak Demand (MW)

Year	ML&P	Chugach	GVEA	HEA	MEA	Total	Total From BVI Table 5-9	Scenario growth Adj	Set to Use	Demand to Use Includes Target Reserve Margin
1996	151	381	127	73	94	659	634.17	100%	634.17	672.23
1997	152	380	167	73	98	698	672	100%	672	712.32
1998	154	384	196	74	100	733	707	100%	707	749.42
1999	156	389	201	75	101	745	718	100%	718	761.08
2000	158	394	203	76	103	755	728	100%	728	771.68
2001	160	399	208	77	104	768	740	100%	740	784.40
2002	163	405	214	78	106	782	753	100%	753	798.18
2003	166	413	220	79	107	799	770	100%	770	816.20
2004	168	420	228	80	109	816	780	100%	780	826.80
2005	170	424	232	81	111	826	797	100%	797	844.82
2006	173	426	236	81	112	835	805	100%	805	853.30
2007	175	432	241	82	114	847	817	100%	817	866.02
2008	177	439	245	83	116	862	831	100%	831	880.86
2009	179	446	250	85	117	876	845	100%	845	895.70
2010	182	453	255	86	118	890	859	100%	859	910.54
2011	184	461	260	87	119	905	874	100%	874	926.44
2012	187	470	266	89	120	922	890	100%	890	943.40
2013	189	478	271	91	122	938	906	100%	906	960.36
2014	192	487	276	92	123	955	923	100%	923	978.38
2015	195	497	282	94	124	974	933	100%	933	988.98
2016	197	506	288	96	125	991	957	100%	957	1,014.42
2017	200	514	296	97	127	1,009	975.1600	100%	975.16	1,033.67
2018	203	521	304	98	129	1,028	993.7050	100%	993.71	1,053.33
2019	205	529	313	100	130	1,048	1012.644	100%	1012.6	1,073.40
2020	208	537	322	101	132	1,068	1031.9864	100%	1032	1,093.91
2021	211	546	332	102	134	1,089	1051.7417	100%	1051.7	1,114.85
2022	214	554	341	104	136	1,109	1071.919	100%	1071.9	1,136.23
2023	217	562	351	105	137	1,131	1092.5302	100%	1092.5	1,158.08
2024	220	571	362	107	139	1,153	1113.583	100%	1113.6	1,180.40
2025	223	580	372	108	141	1,175	1135.0909	100%	1135.1	1,203.20
2026	226	588	383	110	143	1,198	1157.062	100%	1157.1	1,226.49
2027	229	597	394	111	145	1,221	1179.5096	100%	1179.5	1,250.28
AAGR	1.39	1.52	2.91	1.40	1.32					

Chugach's peak demand includes AEG&T, HEA, MEA, and SES.
AAGR = Annual Average Growth Rate over 1997 - 2016.

Table 41: 2% Additional Annual Load Growth (Scenario 18)

Spinning Reserve Margin:	6%

Data from BVI Table 3-1. Expected Peak Demand (MW)

Year	ML&P	Chugach	GVEA	HEA	MEA	Total	Total From BVI Table 5-9	Scenario growth Adj	Set to Use	Demand to Use Includes Target Reserve Margin
1996	151	381	127	73	94	659	634.17	102%	634.17	685.67
1997	152	380	167	73	98	698	672	104%	672	741.10
1998	154	384	196	74	100	733	707	106%	707	795.29
1999	156	389	201	75	101	745	718	108%	718	823.82
2000	158	394	203	76	103	755	728	110%	728	852.00
2001	160	399	208	77	104	768	740	113%	740	883.36
2002	163	405	214	78	106	782	753	115%	753	916.86
2003	166	413	220	79	107	799	770	117%	770	956.31
2004	168	420	228	80	109	816	780	120%	780	988.10
2005	170	424	232	81	111	826	797	122%	797	1,029.83
2006	173	426	236	81	112	835	805	124%	805	1,060.97
2007	175	432	241	82	114	847	817	127%	817	1,098.32
2008	177	439	245	83	116	862	831	129%	831	1,139.49
2009	179	446	250	85	117	876	845	132%	845	1,181.86
2010	182	453	255	86	118	890	859	135%	859	1,225.47
2011	184	461	260	87	119	905	874	137%	874	1,271.80
2012	187	470	266	89	120	922	890	140%	890	1,320.99
2013	189	478	271	91	122	938	906	143%	906	1,371.63
2014	192	487	276	92	123	955	923	146%	923	1,425.31
2015	195	497	282	94	124	974	933	149%	933	1,469.57
2016	197	506	288	96	125	991	957	152%	957	1,537.52
2017	200	514	296	97	127	1,009	975.1600	155%	975.16	1,598.03
2018	203	521	304	98	129	1,028	993.7050	158%	993.71	1,660.99
2019	205	529	313	100	130	1,048	1012.644	161%	1012.6	1,726.50
2020	208	537	322	101	132	1,068	1031.986	164%	1032	1,794.67
2021	211	546	332	102	134	1,089	1051.741	167%	1051.7	1,865.60
2022	214	554	341	104	136	1,109	1071.919	171%	1071.9	1,939.42
2023	217	562	351	105	137	1,131	1092.530	174%	1092.5	2,016.25
2024	220	571	362	107	139	1,153	1113.583	178%	1113.6	2,096.20
2025	223	580	372	108	141	1,175	1135.090	181%	1135.1	2,179.42
2026	226	588	383	110	143	1,198	1157.062	185%	1157.1	2,266.04
2027	229	597	394	111	145	1,221	1179.509	188%	1179.5	2,356.20
AAGR	1.39	1.52	2.91	1.40	1.32					

Chugach's peak demand includes AEG&T, HEA, MEA, and SES.
AAGR = Annual Average Growth Rate over 1997 - 2016.

Table 42: 1.5% Less Annual Load Growth (Scenario 19)

Spinning Reserve Margin:	6%

Data from BVI Table 3-1. Expected Peak Demand (MW)

Year	ML&P	Chugach	GVEA	HEA	MEA	Total	Total From BVI Table 5-9	Scenario growth Adj	Set to Use	Demand to Use Includes Target Reserve Margin
1996	151	381	127	73	94	659	634.17	99%	634.17	662.14
1997	152	380	167	73	98	698	672	97%	672	691.11
1998	154	384	196	74	100	733	707	96%	707	716.20
1999	156	389	201	75	101	745	718	94%	718	716.43
2000	158	394	203	76	103	755	728	93%	728	715.51
2001	160	399	208	77	104	768	740	91%	740	716.40
2002	163	405	214	78	106	782	753	90%	753	718.05
2003	166	413	220	79	107	799	770	89%	770	723.25
2004	168	420	228	80	109	816	780	87%	780	721.65
2005	170	424	232	81	111	826	797	86%	797	726.32
2006	173	426	236	81	112	835	805	85%	805	722.60
2007	175	432	241	82	114	847	817	83%	817	722.37
2008	177	439	245	83	116	862	831	82%	831	723.73
2009	179	446	250	85	117	876	845	81%	845	724.89
2010	182	453	255	86	118	890	859	80%	859	725.84
2011	184	461	260	87	119	905	874	79%	874	727.44
2012	187	470	266	89	120	922	890	77%	890	729.65
2013	189	478	271	91	122	938	906	76%	906	731.62
2014	192	487	276	92	123	955	923	75%	923	734.17
2015	195	497	282	94	124	974	933	74%	933	730.99
2016	197	506	288	96	125	991	957	73%	957	738.55
2017	200	514	296	97	127	1,009	975.1600	72%	975.16	741.27
2018	203	521	304	98	129	1,028	993.7050	71%	993.71	744.04
2019	205	529	313	100	130	1,048	1012.644	70%	1012.6	746.85
2020	208	537	322	101	132	1,068	1031.986	69%	1032	749.70
2021	211	546	332	102	134	1,089	1051.741	68%	1051.7	752.59
2022	214	554	341	104	136	1,109	1071.919	66%	1071.9	755.52
2023	217	562	351	105	137	1,131	1092.530	65%	1092.5	758.50
2024	220	571	362	107	139	1,153	1113.583	65%	1113.6	761.52
2025	223	580	372	108	141	1,175	1135.090	64%	1135.1	764.58
2026	226	588	383	110	143	1,198	1157.062	63%	1157.1	767.69
2027	229	597	394	111	145	1,221	1179.509	62%	1179.5	770.84
AAGR	1.39	1.52	2.91	1.40	1.32					

Chugach’s peak demand includes AEG&T, HEA, MEA, and SES.
AAGR = Annual Average Growth Rate over 1997 - 2016.

Fuel Costs

Table 1: Fuel Costs – Base Case

Model Code:	1	2	3	4	5	6	7	8	9
Utility	ML&P	Chugach			HEA	GVEA			
Plant	MLP	Beluga	Bernice	Int'l	Soldotna	Healy	North	Zehnder	Chena
Unit(s)		1 to 8	2 to 4	1 to 3	1	1	Pole		6
Fuel	NG	NG	NG	NG	NG	Coal	Hago	Hago	Hago
1996	$ 1.86	$ 1.17	$ 1.38	$ 1.98	$ 1.98	$ 1.36	$ 3.00	$ 3.21	$ 3.40
1997	$ 1.74	$ 1.46	$ 1.50	$ 2.25	$ 2.25	$ 1.39	$ 3.09	$ 3.31	$ 3.40
1998	$ 1.97	$ 1.69	$ 1.70	$ 2.05	$ 2.05	$ 1.02	$ 3.18	$ 3.41	$ 3.50
1999	$ 2.01	$ 1.73	$ 1.75	$ 2.10	$ 2.10	$ 0.94	$ 3.28	$ 3.51	$ 3.61
2000	$ 2.06	$ 1.78	$ 1.80	$ 2.15	$ 2.15	$ 0.97	$ 3.38	$ 3.62	$ 3.72
2001	$ 2.12	$ 1.84	$ 1.85	$ 2.20	$ 2.20	$ 0.99	$ 3.48	$ 3.73	$ 3.83
2002	$ 2.16	$ 1.88	$ 1.90	$ 2.25	$ 2.25	$ 1.05	$ 3.58	$ 3.84	$ 3.94
2003	$ 2.22	$ 1.94	$ 1.95	$ 2.30	$ 2.30	$ 1.07	$ 3.69	$ 3.95	$ 4.06
2004	$ 2.27	$ 1.99	$ 2.00	$ 2.35	$ 2.35	$ 1.09	$ 3.80	$ 4.07	$ 4.18
2005	$ 2.33	$ 2.05	$ 2.06	$ 2.41	$ 2.41	$ 1.11	$ 3.91	$ 4.19	$ 4.31
2006	$ 2.39	$ 2.11	$ 2.12	$ 2.47	$ 2.47	$ 1.13	$ 4.03	$ 4.32	$ 4.44
2007	$ 2.44	$ 2.16	$ 2.18	$ 2.53	$ 2.53	$ 1.16	$ 4.15	$ 4.45	$ 4.57
2008	$ 2.50	$ 2.22	$ 2.24	$ 2.59	$ 2.59	$ 1.18	$ 4.28	$ 4.58	$ 4.71
2009	$ 2.57	$ 2.29	$ 2.30	$ 2.65	$ 2.65	$ 1.20	$ 4.41	$ 4.72	$ 4.85
2010	$ 2.63	$ 2.35	$ 2.37	$ 2.72	$ 2.72	$ 1.22	$ 4.54	$ 4.86	$ 4.99
2011	$ 2.70	$ 2.42	$ 2.44	$ 2.79	$ 2.79	$ 1.25	$ 4.67	$ 5.01	$ 5.14
2012	$ 2.77	$ 2.49	$ 2.50	$ 2.85	$ 2.85	$ 1.27	$ 4.81	$ 5.16	$ 5.30
2013	$ 2.84	$ 2.56	$ 2.57	$ 2.92	$ 2.92	$ 1.29	$ 4.96	$ 5.31	$ 5.46
2014	$ 2.91	$ 2.63	$ 2.65	$ 3.00	$ 3.00	$ 1.32	$ 5.11	$ 5.47	$ 5.62
2015	$ 2.98	$ 2.70	$ 2.72	$ 3.07	$ 3.07	$ 1.34	$ 5.26	$ 5.64	$ 5.79
2016	$ 3.06	$ 2.78	$ 2.80	$ 3.15	$ 3.15	$ 1.37	$ 5.42	$ 5.80	$ 5.96
2017	$ 3.13	$ 2.85	$ 2.88	$ 3.23	$ 3.23	$ 1.40	$ 5.57	$ 5.96	$ 6.13

Table 2: Equalized Fuel Costs – Scenario 3

Model Code:	1	2	3	4	5	6	7	8	9
Utility	ML&P	Chugach			HEA	GVEA			
Plant	MLP	Beluga	Bernice	Int'l	Soldotna	Healy	North	Zehnder	Chena
Unit(s)		1 to 8	2 to 4	1 to 3	1	1	Pole		6
Fuel	NG	NG	NG	NG	NG	Coal	Hago	Hago	Hago
1996	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.36	$ 3.00	$ 3.21	$ 3.40
1997	$ 1.46	$ 1.46	$ 1.46	$ 1.46	$ 1.46	$ 1.39	$ 3.09	$ 3.31	$ 3.40
1998	$ 1.69	$ 1.69	$ 1.69	$ 1.69	$ 1.69	$ 1.02	$ 3.18	$ 3.41	$ 3.50
1999	$ 1.73	$ 1.73	$ 1.73	$ 1.73	$ 1.73	$ 0.94	$ 3.28	$ 3.51	$ 3.61
2000	$ 1.78	$ 1.78	$ 1.78	$ 1.78	$ 1.78	$ 0.97	$ 3.38	$ 3.62	$ 3.72
2001	$ 1.84	$ 1.84	$ 1.84	$ 1.84	$ 1.84	$ 0.99	$ 3.48	$ 3.73	$ 3.83
2002	$ 1.88	$ 1.88	$ 1.88	$ 1.88	$ 1.88	$ 1.05	$ 3.58	$ 3.84	$ 3.94
2003	$ 1.94	$ 1.94	$ 1.94	$ 1.94	$ 1.94	$ 1.07	$ 3.69	$ 3.95	$ 4.06
2004	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.09	$ 3.80	$ 4.07	$ 4.18
2005	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 1.11	$ 3.91	$ 4.19	$ 4.31
2006	$ 2.11	$ 2.11	$ 2.11	$ 2.11	$ 2.11	$ 1.13	$ 4.03	$ 4.32	$ 4.44
2007	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 2.16	$ 1.16	$ 4.15	$ 4.45	$ 4.57
2008	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 2.22	$ 1.18	$ 4.28	$ 4.58	$ 4.71
2009	$ 2.29	$ 2.29	$ 2.29	$ 2.29	$ 2.29	$ 1.20	$ 4.41	$ 4.72	$ 4.85
2010	$ 2.35	$ 2.35	$ 2.35	$ 2.35	$ 2.35	$ 1.22	$ 4.54	$ 4.86	$ 4.99
2011	$ 2.42	$ 2.42	$ 2.42	$ 2.42	$ 2.42	$ 1.25	$ 4.67	$ 5.01	$ 5.14
2012	$ 2.49	$ 2.49	$ 2.49	$ 2.49	$ 2.49	$ 1.27	$ 4.81	$ 5.16	$ 5.30
2013	$ 2.56	$ 2.56	$ 2.56	$ 2.56	$ 2.56	$ 1.29	$ 4.96	$ 5.31	$ 5.46
2014	$ 2.63	$ 2.63	$ 2.63	$ 2.63	$ 2.63	$ 1.32	$ 5.11	$ 5.47	$ 5.62
2015	$ 2.70	$ 2.70	$ 2.70	$ 2.70	$ 2.70	$ 1.34	$ 5.26	$ 5.64	$ 5.79
2016	$ 2.78	$ 2.78	$ 2.78	$ 2.78	$ 2.78	$ 1.37	$ 5.42	$ 5.80	$ 5.96
2017	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 2.85	$ 1.40	$ 5.57	$ 5.96	$ 6.13

Table 1: Load Duration Curves by Area (sorted by system load level)

# of Hours	LDC hour	MLP	CEA	GVEA	System
20	0	131	366	120	617
20	20	132	359	113	605
20	40	130	358	113	601
20	60	130	354	111	596
20	80	129	354	110	592
20	100	129	352	107	588
20	120	127	349	109	585
20	140	129	347	107	583
20	160	128	344	108	579
20	180	132	342	103	577
20	200	129	342	104	575
20	220	125	343	105	573
20	240	126	339	106	571
20	260	134	333	103	570
20	280	126	335	107	568
20	300	130	333	103	566
20	320	131	331	102	565
20	340	127	335	101	563
20	360	129	326	105	561
20	380	123	328	108	559
20	400	132	324	102	557
20	420	125	328	103	556
20	440	123	328	104	555
20	460	125	326	102	553
20	480	127	328	98	552
20	500	127	328	96	551
20	520	128	323	99	550
20	540	127	320	102	549
20	560	129	319	99	547
20	580	126	321	99	545
20	600	131	321	92	544
20	620	121	321	101	543
20	640	123	321	98	542
20	660	125	321	96	541
20	680	129	316	96	540
20	700	123	320	96	539
20	720	127	318	93	538
20	740	123	316	98	537
20	760	123	314	98	536
20	780	122	315	97	534
20	800	125	318	90	533
20	820	120	320	92	532
20	840	121	314	95	531
20	860	126	312	92	530
20	880	121	314	94	529
20	900	120	314	94	528
20	920	119	316	92	527
20	940	122	308	96	526
20	960	120	311	94	525
20	980	121	311	91	523
100	1000	118	310	92	520
100	1100	119	304	92	515
100	1200	120	302	88	511
100	1300	116	302	87	506
100	1400	118	296	86	500
100	1500	116	294	86	496
100	1600	116	290	86	492
100	1700	117	288	83	487
100	1800	115	286	82	482
100	1900	113	283	83	478
500	2000	111	274	80	465
500	2500	111	262	76	449
500	3000	112	253	73	438
500	3500	108	248	73	429

# of Hours	LDC hour	MLP	CEA	GVEA	System
500	4000	104	243	72	419
500	4500	99	240	71	410
500	5000	95	235	70	400
500	5500	92	229	69	389
500	6000	87	223	66	376
500	6500	84	213	63	360
500	7000	80	202	59	341
500	7500	76	186	54	316
500	8000	71	172	50	294
260	8500	68	163	47	278

Table 2 Transmission Limits (MW of generation allowed above native demand)

Transmission Scenarios	MLP	CEA	GVEA	Model Code
System Pooled dispatch	20	50	70	0
Individual dispatch	0	26	0	1
Relieve Transmission	500	500	500	2
Equal Split	35	35	70	3
All MLP	70	0	0	4

Table 3 ML&P Costs and Revenue Requirements

FERC Accounts					Allocation Factors				Derivation of Allocation Factors				
	Current	Pg.	Line	Comment	Total Gen	Trans	Dist	Other	Total Gen	Trans	Dist	Public	Total
Rate Base Items													
Original Cost Plant in Service				Original Cost Plant in Service									
301-2	14,113	204	5	Intangible	50%	7%	43%	0%	Use same as common and shared				
	21,134	204	15	Steam	100%								
	-	204	23	Nuclear	100%								
	-	204	32	Hydraulic	100%								
	102,395	206	41	Other	100%								
350-353	17,255	206	53	Transmission	0%	100%	0%	0%					
360-373	105,504	206	69	Distribution			100%						
389-399	37,931	206	83	General Plant	50%	7%	43%	0%	123,529	17,255	105,504		246288
	-	200	4	**Property under Capital Leases**	50%	7%	43%	0%					
Depreciation Reserve													
108	11,616	219	18	Steam	100%								
108	-	219	19	Nuclear	100%								
108	-	219	20	Hydraulic	100%								
108	58,304	219	22	Other Production	100%								
108	7,102	219	23	Transmission	0%	100%	0%	0%					
108	30,554	219	24	Distribution			100%						
108	27,155	219	25	General	50%	7%	43%	0%					
Materials and Supply													
154	688	227	1,7	Fuel and Prod Plant M&S	100%								
	29	227	8	Trans M&S	0%	100%	0%	0%					
	552	227	9	Dist M&S			100%						
	2,323	227	5	Other	50%	7%	43%	0%					
ADFIT	-	113	53	Deferred Taxes	50%	7%	43%	0%	Gross Original plant Cost				
CWIP	8,154	110	3			14%	86%		Gross T&D Original Cost				
Expense Items													
Operations and Maintenance				Operations and Maintenance									
500-507	1,243	320	13	Steam Plant Operations	100%								
510-514	544	320	20	Steam Maint	100%								
517-525	-	320	33	Nuclear Operations	100%								
528-532	-	320	40	Nuclear Maint	100%								
535-540	-	320	50	Hydro Operations	100%								
541-545	-	321	58	Hydro Maint	100%								
546-550	6,272	321	67	Other Power Operations	100%								
551-554	2,251	321	73	Other Power Maint	100%								
555-557	5,281	321	79	Power Purchase etc.	100%								
Transmission Expense Ops				Transmission Expense Ops									
560		321	83		0%	100%	0%	0%					
562		321	84		0%	100%	0%	0%					
563		321	85		0%	100%	0%	0%					
564		321	86		0%	100%	0%	0%					
565		321	87			100%							
566		321	88		0%	100%	0%	0%					
567		321	89		0%	100%	0%	0%					
561	757	321	90			100%							
Transmission Exp Main				Transmission Exp Main									
568		321	93		0%	100%	0%	0%					
569		321	94	Structures		100%							
570		321	95		0%	100%	0%	0%					
571		321	96		0%	100%	0%	0%					
572		321	97		0%	100%	0%	0%					
573	6	321	98		0%	100%	0%	0%					
580-589	3,257	322	114	Distribution Exspense Ops			100%						
590-598	2,472	322	125	Dist Exp Maint			100%						
901-905	2,685	322	134	Customer Accounts Exp			0%	100%					
907-910	133	322	141	Customer Service				100%					
920-932	3,274	322-3	165	A&G	50%	7%	43%	0%					
Depreciation Expense				Depreciation Expense									
403	339	336	2	Steam	100%								
403	-	336	3	Nuclear	100%								
403	-	336	4	Hydraulic	100%								
403	4,692	336	6	Other Production	100%								
403	529	336	7	Transmission	0%	100%	0%	0%					
403	3,309	336	8	Distribution			100%						
403	2,587	336	9	General	50%	7%	43%	0%					
403	550	336	1,10	Common	50%	7%	43%	0%					
190				Taxes									
255													
281													
282													
283													
408													
Taxes													

Table 4 ML&P Unbundled Rate Summary

UNBUNDLED RATE SUMMARY SECTION	Gen	Trans	Dist	Other	Total	
Total Plant	149,632	20,901	127,798	-	298,332	
Depreciation Reserve						
Materials and Supply	1,853	192	1,547	-	3,592	
ADFIT	-	-	-	-	0	Zeroed out due to deferred income taxes
CWIP	-	1,146	7,008	-	8,154	
Net Plant	151,485	22,239	136,353	-	310,078	Total less Dep Res plus M&S less ADFIT plus CWIP
Return	6%	6%	6%	6%		
Return on Rate Base	8,770	1,287	7,894	-	17,951	
Income Tax	2,060	150	1,019	244	3,473	
Total O&M	17,233	992	7,132	2,818	28,175	
Depreciation Expense	6,604	749	4,653	-	12,006	
Subtotal Expenses	23,838	1,741	11,784	2,818	40,181	
Total Rev Req	34,668	3,179	20,697	3,062	61,605	
Retail Rev Req	38,694.07	3,548.35	23,100.44	3,417.14	68,760.00	-10%
Retail Avg Rate	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

This was removed to reconcile difference between Utility Plant shown on p, 110 vs Plant in service on p. 206

Retail Revenu	68,760	P 300 l.10	112%
Resale Reven	2131	P 300 l.12	
Total Revenue	70,891		
Total Operating Revenue	82,575	(P. 114, L. 2)	34%
Retail Sales		p. 304 line 41	
Resale MWh	1244203	p. 311	
Total MWh	1,244,203		

Capital Structure and Tax Costs	p. 112	Cap Structure	Rate	Wtd Rate	Tax	w/ tax
Debt	323189	84%	5%	4%		
Equity	60578	16%	10%	2%	54%	1%
				6%		7%
Taxes		2,060	150	1,019	244	3,473

Table 49 ML&P Annual Growth

wth

Trended Generation

Growth: 1.39%

	Generation Net Book	Depreciation	Return on Net Book	Reduction in Gen Rev Req	Fuel Cost $/MMBTu	Fuel Cost Incr Fctr	Cost Incr w/ Growth	Increase in Fuel Cost	Adjusted Gen Rev Req
1996	41,272	6,604	2,389	382	1.86	1.1	1.1	695	39,771.4
1997	34,668		2,007	-	1.74	1.0	1.0	0	38,694.1
1998	28,063		1,625	(382)	1.97	1.1	1.1	1,893	40,204.5
1999	21,459		1,242	(765)	2.01	1.2	1.2	2,399	40,328.7
2000	14,855		860	(1,147)	2.06	1.2	1.2	2,994	40,540.9
2001	8,250		478	(1,529)	2.12	1.2	1.3	3,680	40,844.3
2002	1,646		95	(1,912)	2.16	1.2	1.3	4,224	41,006.1
2003	(4,959)		(287)	(2,294)	2.22	1.3	1.4	4,940	41,339.7
2004	(11,563)		(669)	(2,676)	2.27	1.3	1.4	5,591	41,608.9
2005	(18,167)		(1,052)	(3,059)	2.33	1.3	1.5	6,340	41,974.9
2006	(24,772)		(1,434)	(3,441)	2.39	1.4	1.6	7,105	42,358.1
2007	(31,376)		(1,816)	(3,823)	2.44	1.4	1.6	7,804	42,674.6
2008	(37,981)		(2,199)	(4,206)	2.5	1.4	1.7	8,604	43,092.1
2009	(44,585)		(2,581)	(4,588)	2.57	1.5	1.7	9,509	43,614.8
2010	(51,189)		(2,963)	(4,970)	2.63	1.5	1.8	10,347	44,070.4
2011	(57,794)		(3,346)	(5,353)	2.7	1.6	1.9	11,293	44,634.3
2012	(64,398)		(3,728)	(5,735)	2.77	1.6	2.0	12,261	45,220.0
2013	(71,003)		(4,111)	(6,118)	2.84	1.6	2.0	13,251	45,828.0
2014	(77,607)		(4,493)	(6,500)	2.91	1.7	2.1	14,264	46,458.6
2015	(84,211)		(4,875)	(6,882)	2.98	1.7	2.2	15,301	47,112.4
2016	(90,816)		(5,258)	(7,265)	3.06	1.8	2.3	16,456	47,885.4
2017	(97,420)		(5,640)	(8,029)	3.132	1.8	2.4	17,560	48,225.1
			NPV(8%)	($25,582)				$57,955	$427,081

Table 50 CEA Costs and Revenue Requirements

FERC Accounts	Current	Pg.	Line	Comment	Allocation Factors Total Gen	Trans	Dist	Other	Derivation of Allocation Factors Total Gen	Trans	Dist	Public	Total
Rate Base Items													
Original Cost Plant in Service				Original Cost Plant in Service									
301-2	4,711	204	5	Intangible	34%	37%	29%	0%	Use same as common and shared				
	61,380	204	15	Steam	100%								
	-	204	23	Nuclear	100%								
	8,950	204	32	Hydraulic	100%								
	113,732	206	41	Other	100%								
350-353	203,223	206	53	Transmission	0%	100%	0%	0%					
360-373	161,393	206	69	Distribution			100%						
389-399	62,075	206	83	General Plant	34%	37%	29%	0%	184,062	203,223	161,393		548678
	56	200	4	**Property under Capital Leases**	34%	37%	29%	0%					
Depreciation Reserve													
108	23,988	219	18	Steam	100%								
108	-	219	19	Nuclear	100%								
108	5,773	219	20	Hydraulic	100%								
108	-	219	22	Other Production	100%								
108	39,185	219	23	Transmission	0%	100%	0%	0%					
108	75,730	219	24	Distribution			100%						
108	52,754	219	25	General	34%	37%	29%	0%					
Materials and Supply													
154	9,282	227	1,7	Fuel and Prod Plant M&S	100%								
	4,072	227	8	Trans M&S	0%	100%	0%	0%					
	2,218	227	9	Dist M&S			100%						
	616	227	5	Other	34%	37%	29%	0%					
ADFIT	-	113	53	Deferred Taxes	34%	37%	29%	0%	Gross Original plant Cost				
CWIP	19,827	110	3			56%	44%		Gross T&D Original Cost				
Expense Items													
Operations and Maintenance				Operations and Maintenance									
500-507	-	320	13	Steam Plant Operations	100%								
510-514	-	320	20	Steam Maint	100%								
517-525	-	320	33	Nuclear Operations	100%								
528-532	-	320	40	Nuclear Maint	100%								
535-540	289	320	50	Hydro Operations	100%								
541-545	198	321	58	Hydro Maint	100%								
546-550	38,066	321	67	Other Power Operations	100%								
551-554	7,327	321	73	Other Power Maint	100%								
555-557	14,033	321	79	Power Purchase etc.	100%								
Transmission Expense Ops				Transmission Expense Ops									
560		321	83		0%	100%	0%	0%					
562		321	84		0%	100%	0%	0%					
563		321	85		0%	100%	0%	0%					
564		321	86		0%	100%	0%	0%					
565		321	87			100%							
566		321	88		0%	100%	0%	0%					
567		321	89		0%	100%	0%	0%					
561	992	321	90			100%							
Transmission Exp Main				Transmission Exp Main									
568		321	93		0%	100%	0%	0%					
569		321	94	Structures		100%							
570		321	95		0%	100%	0%	0%					
571		321	96		0%	100%	0%	0%					
572		321	97		0%	100%	0%	0%					
573	2,386	321	98		0%	100%	0%	0%					
580-589	3,547	322	114	Distribution Exspense Ops			100%						
590-598	5,093	322	125	Dist Exp Maint			100%						
901-905	4,324	322	134	Customer Accounts Exp			0%	100%					
907-910	632	322	141	Customer Service				100%					
920-932	12,108	322-3	165	A&G	34%	37%	29%	0%					
Depreciation Expense				Depreciation Expense									
403	1,693	336	2	Steam	100%								
403	-	336	3	Nuclear	100%								
403	150	336	4	Hydraulic	100%								
403	4,118	336	6	Other Production	100%								
403	5,860	336	7	Transmission	0%	100%	0%	0%					
403	6,101	336	8	Distribution			100%						
403	3,046	336	9	General	34%	37%	29%	0%					
403	-	336	10	Common	34%	37%	29%	0%					
190				Taxes									
255													
281													
282													
283													
408													
Taxes													

Table 51 CEA Unbundled Rate Summary

UNBUNDLED RATE SUMMARY SECTION

	Gen	Trans	Dist	Other	Total	
Total Plant	206,485	227,980	181,054	-	615,520	
Depreciation Reserve	47,458	58,724	91,248	-	197,430	
Materials and Supply	9,489	4,300	2,399	-	16,188	
ADFIT	-	-	-	-	0	Zeroed out due to deferred income taxes
CWIP	-	11,051	8,776	-	19,827	
Net Plant	168,516	184,607	100,982	-	454,105	Total less Dep Res plus M&S less ADFIT plus CWIP
Return	6%	6%	6%	6%		
Return on Rate Base	10,560	11,569	6,328	-	28,458	
Income Tax	444	93	120	31	688	
Total O&M	63,975	7,863	12,202	4,956	88,995	
Depreciation Expense	6,983	6,988	6,997	-	20,968	
Subtotal Expenses	70,958	14,851	19,199	4,956	109,963	
Total Rev Req	81,962	26,513	25,647	4,987	139,109	
Retail Rev Req	53,462.93	17,293.88	16,729.23	3,252.97	90,739.00	
Retail Avg Rate	0.0521	0.0169	0.0163	0.0032	0.0885	

Retail Revenue	90,739	p. 304 line	65%
Resale Revenu	52942	p. 311	
Total Revenue	143,681		
Total Operating Revenue	143,948	(P. 114, L.	3%
Retail Sales	1,025,250	p. 304 line 41	
Resale MWh	1244203	p. 311	
Total MWh	2,269,453		

Capital Structure and Tax Costs

	p. 112	Cap Structure	Rate	Wtd Rate	Tax	w/ tax effects
Debt	307906	75%	5%	4%		
Equity	104477	25%	10%	3%	54%	1%
				6%		8%
Taxes		444	93	120	31	688

Table 52 CEA Annual Growth

Trended Generation (All Costs in Thousands) Growth: 1.52%

	Generation Net Book	Depreciation	Return on Net Book	Reduction in Gen Rev Req	Fuel Cost $/MMBtu	Fuel Cost Incr Fctr	Cost Incr w/ Growth	Increase in Fuel Cost	Adjusted Gen Rev Req
1996	88,945	6,983	5,574	438	1.38	0.9	0.9	-4,913	48,987.9
1997	81,962		5,136	-	1.5	1.0	1.0	0	53,462.9
1998	74,979		4,699	(438)	1.7	1.1	1.2	7,888	60,912.9
1999	67,996		4,261	(875)	1.75	1.2	1.2	10,603	63,191.2
2000	61,014		3,824	(1,313)	1.8	1.2	1.3	13,388	65,538.2
2001	54,031		3,386	(1,750)	1.85	1.2	1.3	16,243	67,955.3
2002	47,048		2,948	(2,188)	1.9	1.3	1.4	19,169	70,444.0
2003	40,065		2,511	(2,626)	1.95	1.3	1.4	22,168	73,005.7
2004	33,082		2,073	(3,063)	2	1.3	1.5	25,242	75,642.2
2005	26,099		1,636	(3,501)	2.06	1.4	1.5	28,787	78,748.8
2006	19,117		1,198	(3,938)	2.12	1.4	1.6	32,421	81,945.4
2007	12,134		760	(4,376)	2.18	1.5	1.7	36,147	85,233.6
2008	5,151		323	(4,814)	2.24	1.5	1.8	39,966	88,615.5
2009	(1,832)		(115)	(5,251)	2.3	1.5	1.8	43,881	92,093.0
2010	(8,815)		(552)	(5,689)	2.37	1.6	1.9	48,319	96,093.2
2011	(15,798)		(990)	(6,126)	2.44	1.6	2.0	52,869	100,206.0
2012	(22,780)		(1,428)	(6,564)	2.5	1.7	2.1	57,097	103,996.0
2013	(29,763)		(1,865)	(7,002)	2.57	1.7	2.2	61,873	108,334.8
2014	(36,746)		(2,303)	(7,439)	2.65	1.8	2.3	67,221	113,244.8
2015	(43,729)		(2,740)	(7,877)	2.72	1.8	2.4	72,247	117,832.7
2016	(50,712)		(3,178)	(8,314)	2.8	1.9	2.5	77,862	123,011.0
2017	(57,694)		(3,616)	(9,190)	2.875	1.9	2.6	83,384	127,657.5
			NPV(8%)	($29,279)				$259,333	$775,415

Table 53 GVEA Costs and Revenue Requirements

FERC Accounts	Current	Pg.	Line	Comment	Allocation Factors Total Gen	Trans	Dist	Other	Derivation of Allocation Factors Total Gen	Trans	Dist	Public	Total
Rate Base Items													
Original Cost Plant in Service				Original Cost Plant in Service									
301-2	-	204	5	Intangible	29%	18%	53%	0%	Use same as common and shared				
	22,136	204	15	Steam	100%								
	-	204	23	Nuclear	100%								
	-	204	32	Hydraulic	100%								
	37,894	206	41	Other	100%								
350-353	37,772	206	53	Transmission	0%	100%	0%	0%					
360-373	112,064	206	69	Distribution			100%						
389-399	22,792	206	83	General Plant	29%	18%	53%	0%	60,030	37,772	112,064		209866
	-	200	4	**Property under Capital Leases**	29%	18%	53%	0%					
Depreciation Reserve													
108	16,526	219	18	Steam	100%								
108	-	219	19	Nuclear	100%								
108	-	219	20	Hydraulic	100%								
108	25,320	219	22	Other Production	100%								
108	23,148	219	23	Transmission	0%	100%	0%	0%					
108	36,852	219	24	Distribution			100%						
108	10,283	219	25	General	29%	18%	53%	0%					
Materials and Supply													
154	3,520	227	1,7	Fuel and Prod Plant M&S	100%								
	108	227	8	Trans M&S	0%	100%	0%	0%					
	108	227	9	Dist M&S			100%						
	2,274	227	5	Other	29%	18%	53%	0%					
ADFIT	-	113	53	Deferred Taxes	29%	18%	53%	0%	Gross Original plant Cost				
CWIP	11,161	110	3			25%	75%		Gross T&D Original Cost				
Expense Items													
Operations and Maintenance				Operations and Maintenance									
500-507	6,936	320	13	Steam Plant Operations	100%								
510-514	1,737	320	20	Steam Maint	100%								
517-525	-	320	33	Nuclear Operations	100%								
528-532	-	320	40	Nuclear Maint	100%								
535-540	-	320	50	Hydro Operations	100%								
541-545	-	321	58	Hydro Maint	100%								
546-550	15,319	321	67	Other Power Operations	100%								
551-554	1,919	321	73	Other Power Maint	100%								
555-557	13,438	321	79	Power Purchase etc.	100%								
Transmission Expense Ops				Transmission Expense Ops									
560		321	83		0%	100%	0%	0%					
562		321	84		0%	100%	0%	0%					
563		321	85		0%	100%	0%	0%					
564		321	86		0%	100%	0%	0%					
565		321	87			100%							
566		321	88		0%	100%	0%	0%					
567		321	89		0%	100%	0%	0%					
561	1,308	321	90			100%							
Transmission Exp Main				Transmission Exp Main									
568		321	93		0%	100%	0%	0%					
569		321	94	Structures		100%							
570		321	95		0%	100%	0%	0%					
571		321	96		0%	100%	0%	0%					
572		321	97		0%	100%	0%	0%					
573	1,035	321	98		0%	100%	0%	0%					
580-589	673	322	114	Distribution Exspense Ops			100%						
590-598	2,154	322	125	Dist Exp Maint			100%						
901-905	2,201	322	134	Customer Accounts Exp			0%	100%					
907-910	619	322	141	Customer Service				100%					
920-932	3,433	322-3	165	A&G	29%	18%	53%	0%					
Depreciation Expense				Depreciation Expense									
403	691	336	2	Steam	100%								
403	-	336	3	Nuclear	100%								
403	-	336	4	Hydraulic	100%								
403	1,163	336	6	Other Production	100%								
403	1,271	336	7	Transmission	0%	100%	0%	0%					
403	3,114	336	8	Distribution			100%						
403	370	336	9	General	29%	18%	53%	0%					
403	-	336	10	Common	29%	18%	53%	0%					
190				Taxes									
255													
281													
282													
283													
408													
Taxes													

Table 54 GVEA Unbundled Rate Summary

UNBUNDLED RATE SUMMARY SECTION	Gen	Trans	Dist	Other	Total					
Total Plant	66,549	41,874	124,234	-	232,658					
Depreciation Reserve	44,787	24,999	42,343	-	112,129					
Materials and Supply	4,170	517	1,322	-	6,010					
ADFIT	-	-	-	-	0	Zeroed out due to deferred income taxes				
CWIP	-	2,814	8,347	-	11,161					
Net Plant	25,933	20,206	91,561	-	137,700	Total less Dep Res plus M&S less ADFIT plus CWIP				
Return	7%	7%	7%	7%						
Return on Rate Base	1,781	1,388	6,288	-	9,457		Retail Revenue	66,282	P 300 l.10	97%
							Resale Revenu	1677	P 300 l.12	
Income Tax	1,080	110	204	72	1,465		Total Revenue	67,959		
Total O&M	40,331	2,961	4,660	2,820	50,772		Total Operating Revenue	69,126	(P. 114, L. 2)	1%
Depreciation Expense	1,960	1,338	3,312	-	6,609					
Subtotal Expenses	42,291	4,298	7,972	2,820	57,381		Retail Sales		p. 304 line 41	
							Resale MWh	1244203	p. 311	
Total Rev Req	45,151	5,796	14,463	2,892	68,303		Total MWh	1,244,203		
Retail Rev Req	43,815.73	5,624.43	14,035.40	2,806.44	66,282.00	3%				
Retail Avg Rate	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!					

Capital Structure and Tax Costs						
	p. 112	Cap Structure	Rate	Wtd Rate	Tax	w/ tax effects
Debt	116459	63%	5%	3%		
Equity	69433	37%	10%	4%	54%	2%
				7%		9%
	Taxes	1,080	110	204	72	1,465

Table 55 GVEA Annual Growth

Trended Generation

Growth: 2.91%

	Generation Net Book	Depreciation	Return on Net Book	Reduction in Gen Rev Req	Fuel Cost $/MMBTu	Fuel Cost Incr Fctr	Cost Incr w/ Growth	Increase in Fuel Cost	Adjusted Gen Rev Req
1996	47,111	1,960	3,235	135	3.4	1.0	1.0	-1,009	42,941.0
1997	45,151		3,101	-	3.4	1.0	1.0	0	43,815.7
1998	43,192		2,966	(135)	3.5	1.0	1.1	2,119	45,800.1
1999	41,232		2,832	(269)	3.61	1.1	1.1	4,442	47,988.8
2000	39,272		2,697	(404)	3.72	1.1	1.2	6,869	50,280.7
2001	37,312		2,562	(538)	3.83	1.1	1.3	9,403	52,679.9
2002	35,352		2,428	(673)	3.94	1.2	1.3	12,048	55,190.4
2003	33,392		2,293	(808)	4.06	1.2	1.4	14,933	57,941.4
2004	31,433		2,159	(942)	4.18	1.2	1.5	17,946	60,819.9
2005	29,473		2,024	(1,077)	4.31	1.3	1.6	21,224	63,963.0
2006	27,513		1,889	(1,211)	4.44	1.3	1.7	24,647	67,251.4
2007	25,553		1,755	(1,346)	4.57	1.3	1.8	28,221	70,690.8
2008	23,593		1,620	(1,481)	4.71	1.4	1.9	32,096	74,431.1
2009	21,633		1,486	(1,615)	4.85	1.4	2.0	36,142	78,342.7
2010	19,674		1,351	(1,750)	4.99	1.5	2.1	40,366	82,432.5
2011	17,714		1,217	(1,884)	5.14	1.5	2.3	44,933	86,864.1
2012	15,754		1,082	(2,019)	5.3	1.6	2.4	49,862	91,658.5
2013	13,794		947	(2,153)	5.46	1.6	2.5	55,009	96,671.5
2014	11,834		813	(2,288)	5.62	1.7	2.7	60,384	101,911.6
2015	9,874		678	(2,423)	5.79	1.7	2.9	66,171	107,563.7
2016	7,915		544	(2,557)	5.96	1.8	3.0	72,213	113,471.2
2017	5,955		409	(2,826)	6.125	1.8	3.2	78,427	119,416.3
			NPV(8%)	($9,005)				$204,446	$642,393

Table 56 Generation Revenue Requirement Trends

	MLP	CEA	GVEA
1996	$ 40	$ 49	$ 43
1997	$ 39	$ 53	$ 44
1998	$ 40	$ 61	$ 46
1999	$ 40	$ 63	$ 48
2000	$ 41	$ 66	$ 50
2001	$ 41	$ 68	$ 53
2002	$ 41	$ 70	$ 55
2003	$ 41	$ 73	$ 58
2004	$ 42	$ 76	$ 61
2005	$ 42	$ 79	$ 64
2006	$ 42	$ 82	$ 67
2007	$ 43	$ 85	$ 71
2008	$ 43	$ 89	$ 74
2009	$ 44	$ 92	$ 78
2010	$ 44	$ 96	$ 82
2011	$ 45	$ 100	$ 87
2012	$ 45	$ 104	$ 92
2013	$ 46	$ 108	$ 97
2014	$ 46	$ 113	$ 102
2015	$ 47	$ 118	$ 108
2016	$ 48	$ 123	$ 113
2017	$ 48	$ 128	$ 119

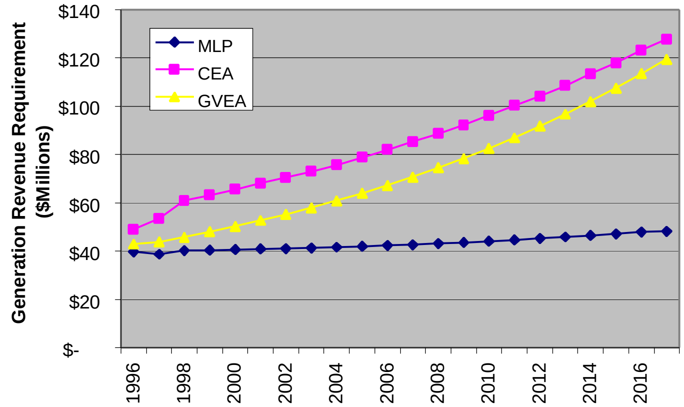


Table 57 Conversion of Table Results for Calculation of Stranded Costs

		Base Case Revenue	Scenario Change in revenue	Increase in IPP Revenue	Net Increase for Utilities	Utility Revenue ($ Millions)	Base Case Cost Change	Increase in Cost	Increase for IPP	NPV Increase in Cost ($Millions)	Note on Costs
Table 5	Base Case	1431	0			1431	-40.94			-40.94	
Table 6	Fuel Cost Equalization	1431	-49.2			1381.8	-40.94	-41.7		-82.64	Relative to Base case w/no IPP
Table 7	Fuel Cost Equalization with Increases MLP Transmission	1431	-45.1			1385.9	-40.94	-46.7		-87.64	Relative to Base case w/no IPP
Table 8	CEA Bids 20% over Marginal Cost, Contract Transmission Capacity	1431	172.2			1603.2	-40.94	6.4		-34.54	Relative to Base case w/no IPP
Table 9	CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP	1431	176.3			1607.3	-40.94	4.9		-36.04	Relative to Base case w/no IPP
Table 10	CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP	1431	118.6			1549.6	-40.94	2.2		-38.74	Relative to Base case w/no IPP
Table 11	CEA Fossil Fleet bids 40% over Marginal Cost	1431	343.9			1774.9	-40.94	10.1		-30.84	Relative to Base case w/no IPP
Table 12	CEA Fleet bids 40% above Marginal Cost, and MLP T Capacity 35MW	1431	346.1			1777.1	-40.94	9.1		-31.84	Relative to Base case w/no IPP
Table 13	CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW T Capacity	1431	348.8			1779.8	-40.94	9.5		-31.44	Relative to Base case w/no IPP
Table 14	Withholding of Beluga 3 by CEA	1431	27.1			1458.1	-40.94	1.3		-39.64	Relative to Base case w/no IPP
Table 15	Withholding of Beluga 7-8 by CEA	1431	44.8			1475.8	-40.94	49		8.06	Relative to Base case w/no IPP
Table 16	Withholding of Beluga 6-8	1431	44.8			1475.8	-40.94	52.6		11.66	Relative to Base case w/no IPP
Table 17	No New Generation Capacity Added	1431	13.2			1444.2	-40.94	-42.3		-83.24	Relative to Base case w/no IPP
Table 23	No Transmission Capacity Constraint	1431	-71.6			1359.4	-40.94	-10.5		-51.44	Relative to Base case w/no IPP
Table 24	MLP Receives 35 MW of Transmission Capacity	1431	5.8			1436.8	-40.94	-1		-41.94	Relative to Base case w/no IPP
Table 25	Load Growth Forecast Increased by 2%	1431	529.3			1960.3	-40.94	365.7		324.76	Relative to Base case w/no IPP
Table 26	Load Growth Forecast Decreased by 1.5%	1431	-257.1			1173.9	-40.94	-199.7		-240.64	Relative to Base case w/no IPP
Table 18	New Entrant in the Status Quo Case		72.9	159.8	-86.9	1344.1		-74	120.6	-194.6	
Table 19	New Entrant in the Pooled Dispatch Base Case		-105.4	111.8	-217.2	1213.8		-37.6	120.6	-158.2	
Table 20	New Entrant when the CEA Fleet Bids 40% above Dispatch Cost		-65.3	168.9	-234.2	1196.8		-39.9	120.6	-160.5	
Table 21	Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)	1213.8	384.1	57	327.1	1540.9	-158.2		0	-158.2	Relative to IPP in base case
Table 22	Impact of IPP on CEA's Withdrawal of Beluga Unit 3	1213.8	22.2	0	22.2	1236	-158.2		0	-158.2	Relative to IPP in base case

Table 58 Calculation of Stranded Costs by Scenario

Scenario		Increase in NPV Revenue	Increase in Costs	Stranded Cost
Table 5	Base Case	($414)	($41)	$373
Table 6	Fuel Cost Equalization	($463)	($83)	$380
Table 7	Fuel Cost Equalization with Increases MLP Transmission	($459)	($88)	$371
Table 8	CEA Bids 20% over Marginal Cost, Contract Transmission Capacity	($242)	($35)	$207
Table 9	CEA Bids 20% Over Marginal Costs, 35 MW Transmission Capacity for MLP	($238)	($36)	$202
Table 10	CEA Bids 20% Over Marginal Costs, 70 MW Transmission Capacity for MLP	($295)	($39)	$257
Table 11	CEA Fossil Fleet bids 40% over Marginal Cost	($70)	($31)	$39
Table 12	CEA Fleet bids 40% above Marginal Cost, and MLP T Capacity 35MW	($68)	($32)	$36
Table 13	CEA Fleet bids 40% above Marginal Cost, and MLP owns 70MW T Capacity	($65)	($31)	$34
Table 14	Withholding of Beluga 3 by CEA	($387)	($40)	$347
Table 15	Withholding of Beluga 7-8 by CEA	($369)	$8	$377
Table 16	Withholding of Beluga 6-8	($369)	$12	$381
Table 17	No New Generation Capacity Added	($401)	($83)	$317
Table 23	No Transmission Capacity Constraint	($485)	($51)	$434
Table 24	MLP Receives 35 MW of Transmission Capacity	($408)	($42)	$366
Table 25	Load Growth Forecast Increased by 2%	$115	$325	$209
Table 26	Load Growth Forecast Decreased by 1.5%	($671)	($241)	$430
Table 18	New Entrant in the Status Quo Case	($501)	($195)	$306
Table 19	New Entrant in the Pooled Dispatch Base Case	($631)	($158)	$473
Table 20	New Entrant when the CEA Fleet Bids 40% above Dispatch Cost	($648)	($161)	$488
Table 21	Impact of CEA Bidding 40% above Dispatch Cost (with IPP in 2002)	($304)	($158)	$146
Table 22	Impact of IPP on CEA's Withdrawal of Beluga Unit 3	($609)	($158)	$451