UTAH DIVISION OF AIR QUALITY
MODIFIED SOURCE PLAN REVIEW

Howard L. Vickers
Environmental Supervisor
Deseret Generation & Transmission Co-operative
12500 East 25500 South
Vernal, Utah 84078

RE:	Notice of Intent for Modification of Bonanza One (1) Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project, Unitah County, CDS-A1, ATT, NSPS, PSD, TITLE V MAJOR
REVIEW ENGINEER:	J. Tim Blanchard
DATE:	January 2, 1998
NOTICE OF INTENT DATED:	December 24, 1997
PLANT CONTACT:	Howard Vickers
PHONE NUMBER:	(435) 781-5706
FAX NUMBER	(435) 781-5816
PLANT LOCATION:	12 Kilometers Northwest of Bonanza Utah
UTM COORDINATES:	4,438,606 m. Northing; 646,206 m. Easting

APPROVALS:

Peer Engineer Mike M. Bebeski 01/28/98
Peer Review Engineer

DAQ requests that a company/corporation official read the attached draft/proposed Approval Order conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER - TECHNICIAN should be contacted within five days after receipt of the conditions. If this person understands and the company/corporation agrees with the Approval Order conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review for final approval. **NOTE: The Approval Order will not be issued until this signed sheet is returned and the review fees are paid.**

Thank You

Applicant Contact Stanley J. Gordon 1/27/98
(Signature & Date)

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TYPE OF IMPACT AREA

Attainment Area ..... Yes

Nonattainment Area
- PM_{10} ..... No
- SO_2 ..... No
- NOx ..... No
- CO ..... No

Maintenance Area
- Ozone ..... No

NSPS ..... Yes
40 CFR Part 60, Subparts A and Da

NESHAP ..... No

Hazardous Air Pollutants (HAPS) ..... Yes[1]

Hazardous Air Pollutants Major Source ..... No
[> 10 tpy of any one Hazardous Air Pollutant (HAP) or > 25 tpy of any combination of HAPs]

New Major Source ..... No

Major Modification ..... No

PSD Permit ..... No

PSD Increment (modeling) ..... No

Send to EPA ..... Yes

Operating Permit Program ..... Yes

FOR MODIFIED SOURCES

The Notice of Intent is for a modification to the emission limits for an existing source. The following standards apply in this review:

NSPS applies to modification? ..... No

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1 Currently exempt from requirements of Section 112 of the Clean Air Act for HAPs.

PSD review of entire source required? ..... No
NESHAPS applies to modification? ..... No
HAPs involved in modification? ..... Yes
TITLE V required for entire source? ..... Yes
HAPs MAJOR for modification? ..... No
NONATT MAJOR for entire source? ..... No

Abstract

Deseret Generation & Transmission Co-operative. (DG&T) is proposing to modify Approval Order (AO) DAQE-706-97 (dated August 4, 1997) by modifying certain emission limits, modifying the Coal Pile parameters, and installing a ruggedized rotor at the Bonanza Power Plant Unit One (1) located in Uintah County. Uintah County is an attainment area for all pollutants. New Source Performance Standards (NSPS) Subparts A and Da apply to this source. National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations do not apply to this source. DG&T is requesting a modification in federally enforceable emission limits which will limit the potential to emit (PTE) for this source. These emission limits are being imposed to demonstrate that any net increase in emissions from the approved facilities will not exceed the threshold emission levels which trigger additional review under state New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. Because of the increased capacity of the Turbine Generator to handle steam flow, there will be a net increase in certain emissions resulting from an overall increase in the heat input to the Boiler from 4381 MMBtu's/Hr to 4578 MMBtu's/Hr. DG&T also proposes to increase the total area of the coal pile to 22 acres and the active reclaim area to 11 acres. The net effect of these projects will be an overall reduction of Bonanza 1's potential emissions, with a significant reduction in NO_x emissions and relatively minor increases in other emissions. DG&T proposes to reduce its potential NO_x emissions by 528.17 TPY and increase the following emissions: particulate emissions 22.60 TPY, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY. A 30-day public comment period was required for DG&T's proposal.

Newspaper Notice

Deseret Generation & Transmission Co-operative. (DG&T) is proposing to modify certain emission limits, modify the coal pile parameters and to install a ruggedized rotor for the Bonanza power plant Unit One (1) located in Uintah County. Uintah County is an attainment area for all pollutants. New Source Performance Standards Subparts A and Da apply to this source. DG&T proposes to reduce its potential NO_x emissions by -528.17 TPY and increase the following emissions: particulate emissions 22.60 TPY, PM_{10} 14.11, TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY. A 30-day public comment period will be required.

I. PROJECT DESCRIPTION

DG&T proposes to modify the emission limits for its Bonanza Unit (1) Power Plant, to modify its Coal Pile Parameters and to install its Ruggedized Rotor Project. DG&T plans to upgrade the Turbine Generator at Bonanza 1 during the year 2000 or 2001 Unit Outage. The upgrade–referred to as the "Ruggedized Rotor Project"–involves the replacement of the HP/IP and LP rotating and stationary equipment. Because the equipment necessary for the Project has a long lead time for design, construction and installation, DG&T is entering into contracts within the next few months to commence construction of the Ruggedized Rotor components. Final installation of the Ruggedized Rotor will take place in the 2000-2001 time frame and is expected to take about 6 weeks. The Project will increase Bonanza 1's generating capacity by at least 28 MW (per vendor representations). DG&T believes that the gross rating of Bonanza 1 could be as much as 500 MW or more (referred to as 500 est. MW) after the upgrade.

Approximately 20 MW from the upgrade will result from an increase in the steam flow produced by the Boiler. To date, the Boiler has not been operated at its peak potential due to limitations of steam flow at the existing Turbine Generator. The Project will allow the Turbine Generator to accept all of the steam flow the

Boiler is capable of producing. While the Ruggedized Rotor, by itself, will not result in any change in Bonanza 1's emissions, the increased capacity of the Turbine Generator to handle the Boiler's peak capacity will increase Bonanza 1's overall potential to emit (PTE).

DG&T submitted a NOI to request the increases in Bonanza 1's overall PTE to allow operation of the Boiler and Turbine Generator at their full capacity. DG&T also recently installed improved low-NO_x burner technology at the boiler which allows DG&T to voluntarily significantly reduce NO_x emissions. The net effect of the proposed emission changes will be to significantly reduce overall plant wide emissions as a result of lower NO_x limits.

DG&T is voluntarily requesting more stringent emission limits for Bonanza 1 to reduce its annual NO_x emissions by -528.17 TPY. DG&T is also requesting certain annual emission limits for other emissions, resulting in an overall increase in the annual potential to emit (PTE) for the Project that is below the levels that might trigger additional review pursuant to new source review (NSR) and prevention of significant deterioration (PSD) requirements. DG&T proposes to increase its PTE for other emissions as follows: particulate emissions 22.60, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY.

DG&T also proposes a change in its Coal Pile parameters to allow the area of the pile to increase to 22 acres and the active reclaim area to increase to 11 acres. The total emission increase from this change will be 3.08 TPY of particulate emissions. The additional emissions will be offset by reducing the hourly PM_{10} emissions rate from 0.03 lb/10^6 BTUs to 0.0297 lb/10^6 BTUs in the emission limit for PM_{10} emissions from the tall stack.

DG&T also reevaluated the hazardous air pollutants (HAPs) listed in their A.O. and determined that the initial emissions rates did not account for any pollution control that would reduce the HAPs emissions. The HAPs emissions listed below reflect these reductions.

II. EMISSION SUMMARY

The allowable emissions from Bonanza 1 are as follows:

Pollutant	Current Emissions tons/year	Emission Change tons/year	Total Allowable tons/year
Particulate	939.96	22.60	962.56
PM_{10}	911.65	14.11	925.76
SO_2	1,929.90	38.21	1,968.11
NO_X	10,558.00	(528.17)	10,029.83
CO	510.85	91.60	602.45
VOC non methane	60.21	10.68	70.89
Arsenic	5.70	(5.36)	0.34
Beryllium	1.52	(1.51)	0.01
Cadmium	0.57	(0.50)	0.07
Chromium	13.30	(9.30)	4.00
Lead	13.30	(12.60)	0.70

Manganese	15.20	(11.75)	3.45
Mercury	0.10	(0.02)	0.08
Nickel	7.60	(5.41)	2.19

Note: (xx) indicate negative

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

BACT was established for Bonanza 1 during its original PSD permitting by EPA and the state in the early 1980's. DG&T submitted an updated BACT analysis for Bonanza 1 as part of the NOI submitted in 1993 and the supplemental documents submitted thereafter. Bonanza 1 currently represents BACT.

IV. APPLICABILITY OF FEDERAL REGULATIONS AND UTAH ADMINISTRATIVE CODES (UAC)

This Notice of Intent is for an increase in emissions by an existing major source. The following federal regulations and state rules have been examined to determine their applicability to this Notice of Intent:

1. R307-1-3.1, UAC - Notice of Intent required for a modified source that is increasing its emissions. This rule applies.

2. R307-1-3.1.5, UAC - Continuous program of construction required to begin within eighteen months of Approval Order date. If a continuous program of construction is not proceeding, the Executive Secretary may revoke the Approval Order. This rule applies.

3. R307-1-3.1.7 (A), UAC - A Notice of Intent is not required for natural gas fuel burning equipment with a rated capacity of less than 5×10^6 BTU per hour. This rule does not apply -- an approval order is required.

4. R307-1-3.1.8 (A), UAC - Application of best available control technology (BACT) required at all emission points. This rule applies for this modification.

5. R307-1-3.1.8 (C), UAC - Approval of the UAQB is required before the Executive Secretary can approve a source under Section 3.6.5 that consumes more than 50% of a PSD increment. This rule does not apply to this NOI because it does not involve any criteria pollutant that consumes 50% of the PSD increment.

6. R307-3-3.3.B (2), UAC - Enforceable offset of 1.2:1 required for new sources or modifications that would produce an emission increase greater than or equal to 50.00 tons per year of any combination of PM_{10}, SO_2, and NO_x. This is required in Salt Lake, Davis, and Utah Counties and in any area that affects these three counties as defined in the rule. The effective date is November 15, 1990. This source is located in Uintah County. Therefore, this rule does not apply.

7. R307-1-3.1.9, UAC - Rules for relocation of temporary sources. This source is a permanent source. Therefore, this rule does not apply.

8. R307-1-3.1.12, UAC - Requirement for installation of low-NO_x burners on all existing sources whenever existing fuel combustion burners are replaced, unless the replacement is not physically practical or cost effective. The effective date is November 15, 1990. This rule does apply to the source but not for this modification. Moreover, Bonanza 1 already utilizes low-NO_x burner technology.

9. R307-1-3.2.1, UAC - Particulate emission limitations for existing sources that are located in a nonattainment area. This rule has been superseded by the PM_{10} SIP, except for Weber County. This source is located in Uintah County. Therefore, this rule does not apply.

10. R307-1-3.3.2, UAC - Review requirements for new major sources or major modifications that are located in a nonattainment area or which impact a nonattainment area. This Notice of Intent does not represent a new major source or a major modification in a nonattainment area or which impacts a nonattainment area. Therefore, this rule does not apply.

11. R307-1-3.5, UAC - Emission inventory reporting requirements. This rule requires any source that emits 25 tons or more per year of any pollutant or any Part 70 source to submit an emission inventory to the Division of Air Quality every year or as determined necessary by the Executive Secretary. This source must comply with this rule.

12. R307-1-3.6.3, UAC - PSD Increment Consumption - This rule lists the allowable PSD increment consumption. This rule applies. Under the PSD rules, the entire state has been triggered for TSP, SO_2, and NO_x. The allowable increments are as follows:

	Three Hour	24 Hour	Annual
PM_{10} ($\mu g/m^3$)			
PSD I Area		8	4
PSD II Area		30	17
SO_2 ($\mu g/m^3$)			
PSD I Area	25	5	2
PSD II Area	512	91	20

	Three Hour	24 Hour	Annual
NO_x ($\mu g/m^3$)			
PSD I Area			2.5
PSD II Area			25.0

There are also PSD III increments, which do not apply in Utah. The above increments apply at all locations, unless the area is already nonattainment. The entire increment may not be available at all locations due to previously permitted sources consuming increment. Modeling analysis is not routinely performed for air pollution sources with emissions below the following levels:

Criteria for Screen Modeling
(≥ Tons per Year)

TSP	25
PM_{10}	15
SO_2	40
NO_x	40
CO	100
VOC	40

13. R307-1-3.6.5 (B), UAC - Prevention of significant deterioration (PSD) review requirements for new major sources or major modifications. This Notice of Intent is not a major modification under PSD rules. Therefore, this rule does not apply.

14. R307-1-3.6.6, UAC - Increment violations. This rule requires the UAQB to promulgate a plan and implement rules to eliminate any PSD increment violations that occur in the state. No known violations have yet occurred.

15. R307-1-3.8, UAC - Stack height rule. This rule limits the creditable height of stacks to that height determined to be good engineering practice (GEP). The formulas used to determine good engineering practice are found in 40 CFR 51.100. A deminimis height of 65 meters (213.2 feet) is allowed. GEP for Bonanza 1 is defined by Section XVIII of the State Implementation Plan. Bonanza 1 is in compliance with this rule.

16. R307-1-3.10, UAC - Visibility screening analysis requirements. This rule requires all new major sources or major modifications to undergo a visibility screening analysis to determine visibility impact on any mandatory PSD I area within 100 kilometers (km) of the source. This Notice of Intent is not a major modification under UACR rules therefore, visibility screening is not required.

17. R307-1-4.1.2, UAC - 20% opacity limitation at all emission points, unless a more stringent limitation is required by New Source Performance Standards (NSPS) or BACT or National Emission Standards for Hazardous Air Pollutants (NESHAPS). In this case, DG&T, is subject to NSPS. NSPS requires 20% opacity limitations.

18. R307-1-4.1.9, UAC - EPA Method 9 shall be used for visible emission observations. This rule applies, except that some sources will comply with opacity limits by using Continuous Emission Monitors (CEM).

19. R307-1-4.2.1, UAC - Sulfur content limitations in oil and coal used for combustion. This source, emission point, burns coal and is subject to NSPS 40 CFR 60 Subpart Da. Therefore, this rule does not apply.

20. R307-1-4.6, UAC - Continuous Emission Monitoring Systems Program - Reporting and technical requirements for continuous emission monitoring systems. This rule applies. It covers breakdowns and quarterly reports for continuous monitoring systems. Section 4.6.5 states that this regulation applies to the following:

A. Sources required to install CEMS as required by the following documents:

1) NSPS
2) State Implementation Plan
3) Approval Order
4) Consent Decree
5) Administrative Orders and Agreements

B. Any source that constructs after the promulgation of this rule, two or more emission points, which may interfere with VEO's, shall install an opacity monitor on each stack.

This source falls under 40 CFR 60 Subpart Da the NSPS for electric utility steam generating units with heat input greater than 250 MMBTU/hour heat input of fossil fuel.

21. R307-1-4.7, UAC - Unavoidable breakdown as defined in R307-1-1 reporting requirements. This rule applies. Section 4.7.1 discusses reporting requirements. A breakdown for any period longer than two hours must be reported to the Executive Secretary within three hours of the beginning of the breakdown, if reasonable, but in no case longer than 18 hours after the beginning of the breakdown. A written report is required within seven calendar days. The report shall include the estimated quantity of pollutants (total and excess). Section 4.7.2 discusses penalties.

22. R307-1-5, UAC - Emergency episode requirements. This rule requires the Executive Secretary to determine the stage and extent of an air pollution episode based on pollution levels and meteorological conditions. Under section 40 of the Code of Federal Regulations, Part 51, Subpart H (51.150 to 153), it is required that sources plan emergency measures based upon the severity of the Non-Attainment area in which they operate. In Utah, these rules require that CO sources in CO Non-Attainment areas and sources of Ozone precursors in Ozone Non-Attainment areas, who emit at least 25 tons per year (see SIP section VII.B.) of either pollutant, submit an Emergency Episode Plan which provides for additional pollution reductions in the event of an Air Pollution Alert, Warning or Emergency Episode. These plans can include total shut-down of the process. (Some sources are required to submit an emergency episode plan in the PM_{10} SIP). This rule applies. This source is located outside of the nonattainment area. Therefore, this rule does not apply.

23. New Source Performance Standards (NSPS) - 40 CFR 60.40 to 60.49, NSPS, Subpart Da (see below) applies to this source.

NSPS Subpart Da

40 CFR 60.40a to 60.49a, NSPS, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978 - This regulation applies. An affected facility is defined as each electric utility steam generating unit capable of combusting more than 250 million BTU/hr heat input. This Subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 250 million BTU/hr heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this Subpart.

An Electric Utility Steam Generating Unit is defined as any unit that is constructed for the purpose of supplying more than one third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam electric generator that would produce electricity for sale is also considered in determining the electrical energy output capacity of the affected facility.

The standards are as follows:

Particulate

On and after the date of the performance test is completed, no owner/operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere any gases which contain particulate matter in excess of:

1) 0.03 lb/MMBTU heat input derived from solid, liquid, or gaseous fuel

2) 1% of the potential combustion concentration (99% reduction) when combusting solid fuel

3) 30% of the potential combustion concentration (70% reduction) when combusting liquid fuel

On and after the date the performance test is completed, no owner/operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere any gases which exhibit greater than 20% opacity, except for one 6 minute period per hour of not more than 27% opacity.

Sulfur Dioxide

On and after the date the performance test is completed, no owner/operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere from any

affected facility which combusts solid fuel (such as coal) or solid-derived fuel, any gases which contain SO_2 in excess of:

1) 1.20 lb/MMBTU heat input and 10% of the potential combustion concentration (90% reduction), or

2) 30% of the potential combustion concentration (70% reduction) when emissions are less than 0.60 lb/MMBTU heat input

Nitrogen Oxides

On and after the date the performance test is completed, no owner/operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere from any affected facility which combusts sub bituminous coal any gases which contain NO_x in excess of 0.60 lb/MMBTU heat input.

"sub" crossed out, per Tim Blanchard phone call w/ Owens on 2/4/98.

Emission Monitoring

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring opacity, except when gaseous fuel is the only fuel used.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring sulfur dioxide, except when gaseous fuel is the only fuel used. Sulfur dioxide emissions shall be measured at both the inlet and outlet of the control device. An "as fired" fuel monitoring system (upstream of coal pulverizers) may be used in place of the CEM at the inlet of the control device.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring NO_x emissions.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring the oxygen or carbon dioxide content of the flue gases at each location where SO_2 or NO_x gases are monitored.

Test Methods

When it becomes necessary to use test methods to supplement CEM data, approved methods from 40 CFR Part 60, Appendix A shall be used.

The procedures in Method 19 shall be used to compute each one hour average concentration in heat input.

For particulate matter, the following test methods apply:

The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

Also see R307-1-1 (Modification), which is the State's definition. It is a planned increase in emissions. The DAQ has determined that this Notice of Intent is a modification.

27. 40 CFR 60.15, Definition of Reconstruction - the replacement of components of an existing facility to such an extent that:

1) The fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility and

affected facility which combusts solid fuel (such as coal) or solid-derived fuel, any gases which contain SO_2 in excess of:

1) 1.20 lb/MMBTU heat input and 10% of the potential combustion concentration (90% reduction), or

2) 30% of the potential combustion concentration (70% reduction) when emissions are less than 0.60 lb/MMBTU heat input

Nitrogen Oxides

On and after the date the performance test is completed, no owner/operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere from any affected facility which combusts sub bituminous coal any gases which contain NO_x in excess of 0.60 lb/MMBTU heat input.

"sub" crossed out, per Tim Blanchard phone call w/ Owens on 2/4/98.

Emission Monitoring

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring opacity, except when gaseous fuel is the only fuel used.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring sulfur dioxide, except when gaseous fuel is the only fuel used. Sulfur dioxide emissions shall be measured at both the inlet and outlet of the control device. An "as fired" fuel monitoring system (upstream of coal pulverizers) may be used in place of the CEM at the inlet of the control device.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring NO_x emissions.

The owner/operator of an affected facility shall install and operate a continuous monitoring system for measuring the oxygen or carbon dioxide content of the flue gases at each location where SO_2 or NO_x gases are monitored.

Test Methods

When it becomes necessary to use test methods to supplement CEM data, approved methods from 40 CFR Part 60, Appendix A shall be used.

The procedures in Method 19 shall be used to compute each one hour average concentration in heat input.

For particulate matter, the following test methods apply:

The dry basis F factor (O_2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems, and Method 5B shall be used after wet FGD systems. The sampling time and sample volume shall be at least 120 minutes and 60 dscf. The probe and filter holder heating system may be set to provide an average temperature of no greater than 320 plus or minus 25°F.

Duct opacity monitors or Method 9 shall be used to determine stack opacity readings.

There are also reporting requirements.

24. National Emission Standards for Hazardous Air Pollutants (NESHAPS) - There is no NESHAPS for this industrial process.

25. National Ambient Air Quality Standards (NAAQS) - This source is located in Uintah County, which is an attainment area for all pollutants.

26. 40 CFR 60.14, Definition of Modification - Any physical or operational change to an existing facility that results in an increase in the emission rate to the atmosphere of any pollutant to which an NSPS standard applies. The following are not by themselves considered modifications:

    1) Maintenance, repair, and replacement

    2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility

    3) An increase in the hours of operation

    4) Use of an alternate fuel or raw material if, before the date any standard under this part becomes applicable to that source type, as provided by 60.1, the existing facility was designed to accommodate that alternative use

    5) The addition or use of any system or device whose primary function is the reduction of air pollutants

    6) Relocation or change in ownership

    Also see R307-1-1 (Modification), which is the State's definition. It is a planned increase in emissions. The DAQ has determined that this Notice of Intent is a modification.

27. 40 CFR 60.15, Definition of Reconstruction - the replacement of components of an existing facility to such an extent that:

    1) The fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility and

2) It is technologically and economically feasible to meet the applicable standards set forth in this part

This Notice of Intent is not a reconstruction.

28. R307-1-1, Definition of Major Modification - It means any physical change in or changes in the method of operation of a major source that would result in a significant net emission increase of any pollutant. A net emissions increase that is significant for VOC shall be considered significant for ozone. A physical change or change in the method of operation shall not include:

A. Routine maintenance, repair, or replacement.

B. Use of an alternative fuel or raw material by reason of an order under Section 2a and b of the ESECA of 1974 or by reason of a natural gas curtailment plan pursuant to the Federal Power Act.

C. Use of an alternative fuel by reason of an order under Section 125 of the CAA.

D. Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste.

E. Use of an alternative fuel or raw material by a source:

1) which the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any enforceable permit condition.

2) which the source is otherwise approved to use.

F. An increase in the hours of operation or the production rate unless such change would be prohibited under any enforceable permit condition.

G. Any change in ownership at a source.

DAQ has determined that this Notice of Intent is not a PSD major modification.

V. RECOMMENDED APPROVAL ORDER CONDITIONS

General conditions:

1. This Approval Order (AO) applies to the following company:

   HOME OFFICE:

   Deseret Generation & Transmission Co-Operative
   5295 South 300 West, Suite 500
   Murray, Utah 84107

   PHONE NUMBER: 801-892-6500
   FAX NUMBER: 801-892-6599

   The equipment listed below in this AO shall be operated at the following location:

   PLANT LOCATION:

   Bonanza Power Station Unit 1
   12 kilometers northwest of Bonanza, Utah
   Uintah County

   Universal Transverse Mercator (UTM) Coordinate System:
   4,438,606 meters Northing, 646,206 meters Easting

2. Definitions of terms, abbreviations, and references used in this AO conform to those used in the Utah Air Conservation Rules (UACR), Utah Administrative Codes (UAC), New Source Performance Standards (NSPS) and Series 40 of the Code of Federal Regulations (40 CFR). These definitions take precedence unless specifically defined otherwise herein.

3. Deseret Generation & Transmission (DG&T) shall operate the 500 est. Megawatt (MW) gross Bonanza Power Station Unit 1 according to the terms and conditions of this Approval Order as requested in the Notice of Intent dated December 24, 1997 and additional information submitted January 5, 1998.

4. At least once per calendar year, all employees who operate equipment (operator) that produces and/or controls emissions to the air shall receive proper training as to their responsibilities in operating that equipment according to all relevant conditions of this AO. The training for each operator shall be for all equipment that operator operates. The equipment shall include all of the associated equipment listed in Conditions # 7, 8, and 9. Within 60 days of every time this AO is modified or reissued, those employees who operate equipment that produces and/or controls emissions to the air that is affected by the AO changes shall receive proper training as to their responsibilities in operating equipment

according to all relevant conditions of this AO. Within 60 days of a new operator being employed or assigned with the job responsibility to operate any of the equipment that produces and/or controls emissions to the air, the new operator shall receive proper training as to their responsibilities in operating the equipment according to all relevant conditions of this AO. Records of operator training shall be made available to the executive secretary or executive secretary's representative upon request and the records shall include the two-year period prior to the date of the request. This AO shall be made available to all employees who operate the equipment listed in this AO.

5. The approved installations shall consist of a 500 est. MW coal fired steam electric generating station and associated equipment.

6. This AO shall replace the AO DAQE-706-97 dated August 4, 1997.

Limitations and tests procedures

7. Sulfur Emission Control

   A. Bonanza 1 shall not discharge to the atmosphere sulfur as SO_2 at a rate exceeding 0.0976 lb/MMBTU heat input over a rolling 12-month average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the rolling 12-month average. On the first day of each month a new 12-month average shall be calculated using data from the previous 12 months.

   B. Bonanza 1 shall achieve at least 90% SO_2 removal efficiency based on a 30-day rolling average.

   C. Bonanza 1 SO_2 emissions shall not exceed 0.15 lb/MMBTU heat input as averaged over 30 successive boiler operating days.

   D. To achieve the limits above, DG&T may use scrubber slurry additives (such as adipic acid etc.) to increase the dissolved alkalinity of the slurry reagent used in the FGD scrubber.

   E. Compliance with the SO_2 removal requirements shall be based on data from outlet SO_2 continuous emissions monitors (CEM), and either inlet SO_2 data from CEM or coal analysis data, over a 30-day rolling average. The total percent removal may be computed using the total available sulfur from the coal analysis and overall sulfur removal. Compliance shall be determined by calculating the arithmetic average for all valid hourly emissions rates for SO_2 for the 30 successive boiler operating days.

8. Nitrogen Oxides Emission Control

A. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MMBTU heat input on an annual average. Compliance with this emission limitation shall be determined in accordance with 40 CFR 76.5(b).

B. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.55 lb NO_x/MMBTU heat input as a 30-day rolling average value averaged over 30 successive boiler operating days. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the arithmetic average of all valid hourly emission rates (at least two values each hour are required) for NO_x for 30 successive boiler operating days.

9. Particulate and PM_{10} Emission Control

A. Unit No. 1 shall not discharge to the atmosphere particulate matter at a rate exceeding 0.0297 lbs/MMBTU BTU heat input as determined by 40 CFR 60, Appendix A, Methods 1-5 and 19.

B. Unit No. 1 shall not discharge to the atmosphere PM_{10} particulate matter at a rate exceeding 0.0286 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix A, Methods 1, 2, 4, 5-5e and 19.

C. Visible emissions from any source shall not exceed 20% opacity as determined primarily by CEM equipment, except for one six-minute period per hour of not more than 27% opacity for the tall stack, as determined by CEM equipment. However, EPA Method 9 may be used when the opacity CEM equipment is not operating.

D. Dust collectors DC-1 through 5, LDC 1 and 2, and the fly ash silo dust collector shall be maintained and operated per manufacturer's recommendations.

DC-4 and DC-5 stacks shall be made testable and TSP emissions shall not exceed 0.02 grains/dscf (PM_{10} = 0.018 grains/dscf). The stacks shall be tested in accordance with 40 CFR 60, Appendix A, Methods 1-5 upon the direction of the Executive Secretary.

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emission Point	Pollutant	Testing Status	Test Frequency
Unit No. 1			
600 foot stack	TSP	*	@
	PM_{10}	*	@
	SO_2	*	@

	NO_x	*	@
DC-4 and DC-5	PM_{10}	**	#

B. Testing Status (To be applied above)

* Compliance testing is required. The initial testing shall be done in 1995. Alternatively, data from testing done in conjunction with the installation, calibration and certification of the new CEM system in 1994 may be used.

** No initial testing is required. However, the Executive Secretary may require testing at any time in accordance with R307-1-3.4.1, UAC. The source shall be tested if directed by the Executive Secretary.

\# Test if directed by the Executive Secretary. Tests may be required if the source is suspected to be in violation with other conditions of this AO.

@ Test every five (5) years

C. Notification

The applicant shall provide a notification of the test date at least 30 days before the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days before the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approvable access shall be provided to the test location.

D. TSP

40 CFR 60. Appendix A, Method 5

E. PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201 or 201a. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5D, or 5E as appropriate. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch

considered PM_{10} shall be based on information in AP-42, Appendix C or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

F. Sample Location

40 CFR 60. Appendix A, Method 1

G. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or any alternative method that has the approval of UDAQ or EPA.

H. Sulfur Dioxide (SO_2)

40 CFR 60, Appendix A, Method 6, 6A, 6B or 6C

I. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E

J. Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide and Nitrogen Oxides Emissions Rates

40 CFR 60, Appendix A, Method 19

K. Calculations

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

L. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum capacity unless approved by the Executive Secretary.

Roads and Fugitives

11. Coal and limestone conveyors shall be enclosed and all drop points shall be vented to fabric dust collectors.

12. The track hopper for bottom dump coal cars shall have water sprays in place. The water spray shall be used during dumping when conditions warrant. Conditions which warrant operation of the sprays are defined as any time the 20% opacity limitation is in jeopardy of being violated. To ensure that the sprays are always operative, the equipment shall be tested at least once per month, except when whether conditions prohibit. A log of testing and operation shall be kept. The log shall include:

    A. Times of testing.
    B. Times of coal deliveries
    C. Times of spray operation
    D. Weather conditions at time of coal deliveries
    E. Coal conditions (washed, unwashed, dry, moist, etc.)

13. The coal pile shall not exceed 22 acres in total area. The active reclaim area shall not exceed 11 acres at any one time. The reclaim area may be moved to any location on the coal pile. The remainder of the coal pile shall be the long-term storage area. Emissions of particulate from the long-term storage area shall be controlled by compaction of the coal pile surface and sealing with a surfactant initially and by subsequent application of sealing agent as warranted. A surfactant and spray mechanism to apply it shall be available and operative at all times. Conditions which warrant application of the surfactant are defined as any time the 20% opacity limitation is in jeopardy of being violated. A log of operation shall be kept. The log shall include:

    A. Times of spray operation
    B. Compaction operation
    C. Weather conditions
    D. Surface conditions (dry, crumbled, moist, etc.)

14. The long term limestone storage shall be sealed with a surfactant as dry conditions warrant or as determined necessary by the Executive Secretary.

15. The limestone receiving hopper shall be partly enclosed with a wind break.

16. The fly ash/FGD sludge mixture at the end of the conveyor and prior to being completely covered in accordance with landfill procedures, shall be water sprayed to minimize fugitive emissions as conditions warrant.

    A record/log of stabilizing done shall be kept which includes dates, type of stabilizing agent, amount applied, and area of application.

17. All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed and/or chemically treated to control fugitive dust. The application of water or chemical treatment shall be used. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition. The opacity shall not exceed 20% during all times the areas are in use or unless it is below freezing. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of

water treatment shall be kept for all periods when the plant is in operation. The records shall include the following items:

A. Date
B. Number of treatments made, dilution ratio, and quantity
C. Rainfall received, if any, and approximate amount
D. Time of day treatments were made

Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

18. Visible emissions from haul-road traffic and mobile equipment in operational areas shall be controlled by use of a dust control plan.

Fuels

19. DG&T shall use only coal and natural gas as a primary fuel and fuel oil or natural gas during startup, shut down, upset conditions and flame stabilization. DG&T may burn on-spec used oil, off-spec used oil and small quantities of self generated hazardous waste (<850 gallons/month) as specified in State and Federal regulations. If any other fuel is to be used, an AO shall be required in accordance with R307-1-3.1, UAC.

20. The sulfur content of any fuel oil or diesel burned shall not exceed 0.5 percent by weight. Sulfur content shall be decided by ASTM Method D-4294-89, or approved equivalent. The sulfur content shall be tested if directed by the executive secretary.

21. Boilers burning used oil for energy recovery shall comply with the following:

A. The concentration/parameters of contaminants in the used oil shall not exceed the following levels:

1.	Arsenic	5	ppm by weight
2.	Cadmium	2	ppm by weight
3.	Chromium	10	ppm by weight
4.	Lead	100	ppm by weight
5.	Total halogens	1,000	ppm by weight
6.	Sulfur	0.5	percent by weight

B. The flash point of all used oil to be burned shall not be less than 100 °F.

C. The owner/operator shall provide test certification for each load of used oil received. Certification shall be either by their own testing or test reports from the used oil fuel marketer. Records of used oil fuel consumption and the test reports shall be kept for all periods when the plant is in operation. Records shall be made available to the executive secretary or her representative upon request. The records shall include a period of three years ending with the date of the request.

D. Used oil (off-spec) that does exceed any of the listed contaminants content may be burned, but owner/operator shall notify the Division of Solid and Hazardous Waste and EPA. The owner/operator shall record the quantities of used oil burned on a daily basis.

E. Used oil that contains more than 1000 ppm by weight of total halogens shall be considered a hazardous waste and can be burned at a maximum rate of 850 gallons/month. The used oil shall be tested for halogen content by ASTM Method D-808-81, EPA Method 8240 or Method 8260 before used oil fuel is transferred to the boiler fuel tank and burned. Small quantities self generated hazardous used fuels are regulated by 40 CFR 266.108(a) "Small Quantity On-site Burner Exemptions".

F. Sources utilizing used oil as a fuel shall comply with the State Division of Solid and Hazardous Waste in accordance with R315-15, UAC "Used Oil Management Rule".

Federal Limitations and Requirements

22. In addition to the requirements of this AO, all provisions of 40 CFR 60, NSPS Subparts A and Da, 40 CFR 60.40a to 60.49a (Standards of Performance for opacity, SO_2, and NO_x) apply to this installation.

Monitoring - General Process

23. All air quality monitoring must conform to the requirements of 40 CFR, Part 58. As part of the air quality monitoring program, a quality control program shall be used and it shall consist of policies, procedures, specifications, standards, and documentation necessary to:

    A. Meet the monitoring objective and quality assurance requirements of the Executive Secretary.

    B. Minimize loss of air quality data due to malfunction or out of control conditions.

24. The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring (CEM) system on the 600 foot stack. The owner/operator shall record the output of the system, for measuring the opacity of emissions, the SO_2 emissions, the NO_x emissions, and diluent. Procedures to be followed for (1) testing, monitoring, and reporting of excess emissions of particulates, opacity, sulfur dioxide and nitrogen oxides, and for (2) the purpose of demonstrating compliance with the emission limitations of Conditions (7), (8), and (9) are specified in the applicable section of 40 CFR 60.7, 60.8, 60.11, 60.13, Subpart Da, Appendix A, Methods 1-7, Appendix B, Performance Specifications 1, 2, and 3, Appendix F, and the state CEM policy document (all applicable sections of R307-1-4.6, UAC).

25. A quality control/assurance plan/manual for the continuous monitoring system shall be developed and implemented. As a minimum, the quality control program shall have written procedures for each of the following activities:

A. Installation of CEM's
B. Calibration of CEM's
C. Zero and calibration checks and adjustments for CEM's
D. Preventive maintenance for CEM's (including parts inventory)
E. Data recording and reporting
F. Program of corrective action for inoperable CEM's
G. Annual evaluation of CEM system

Records & Miscellaneous

26. All installations and facilities authorized by this AO shall be adequately and properly maintained. All pollution control vendor recommended equipment shall be installed, maintained, and operated. Instructions from the vendor or established maintenance practices that maximize pollution control shall be used. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, CEMs, etc., shall be installed and operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instruction for pollution control equipment and pollution emitting equipment shall be kept on site. These instructions shall be available to all employees who operate the equipment and shall be made available to compliance inspectors upon their request.

27. The owner/operator shall comply with R307-1-3.5, UAC. This rule addresses emission inventory reporting requirements.

28. The owner/operator shall comply with R307-1-4.7, UAC. This rule addresses unavoidable breakdown reporting requirements. The owner/operator shall calculate/estimate the excess emissions whenever a breakdown occurs. The total of excess emissions shall be reported to the Executive Secretary as directed for each calendar year.

All records referenced in this AO or in applicable NSPS or NESHAP, which are required to be kept by the owner/operator, shall be made available to the executive secretary or her representative upon request and shall include a period of two years ending with the date of the request. All records shall be kept for a period of two years (used oil records are to be kept for a period of three years). Examples of records to be kept at this source shall include the following as applicable:

A. Test results ..... Conditions 7,8 & 9
B. Maintenance records ..... Condition 26
C. Upset, breakdown episodes ..... Condition 28
D. Fugitive emission control ..... Conditions 12, 13, 16 & 17
E. CEM records ..... Condition 24
F. Fuel consumption ..... Condition 21
G. Training ..... Condition 4

Any future modifications to the equipment approved by this order must also be approved in accordance with R307-1-3.1.1, UAC.

The Executive Secretary shall be notified in writing if the company is sold or changes its name. The notification shall be submitted within 30 days of such action.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including the Utah Air Conservation Rules.

Annual emissions for this source the entire plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	Particulate	962.56
B.	PM_{10}	925.76
C.	SO_2	1,968.11
D.	No_x	10,029.83
E.	CO	602.45
F.	VOC non methane	70.89
G.	Arsenic	0.34
H.	Beryllium	0.01
I.	Cadmium	0.07
J.	Chromium	4.00
K.	Lead	0.70
L.	Manganese	3.45
M.	Mercury	0.08
N.	Nickel	2.19

These calculations are for the purposes of determining the applicability of Prevention of Significant Deterioration, nonattainment area, and Title V source requirements of the UAC R307.

In accordance with the requirements of Title V of the 1990 Clean Air Act, the following pollutants may be subject to an operating permit fee. Emissions of the following pollutants from all sources, including pre-November 29, 1969 sources, may be subject to the operating permit fee. Both the fees rate and the class of pollutants are subject to change by State, the federal agencies, or both.

	Pollutant	Tons/yr
A.	PM_{10}	925.76
B.	SO_2	1,968.11
C.	NO_x	10,029.83
D.	VOC non methane	70.89
E.	HAPs	10.84