# Statement of Basis

**Permit to Construct No. P-2009.0092**
**Project ID 61199**

**Idaho Power Company - Langley Gulch Power Plant**
**New Plymouth, Idaho**

**Facility ID 075-00012**

**Final**

**August 14, 2013**
**Morrie Lewis**
**Permit Writer**

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

## 1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

| | |
|---|---|
| acfm | actual cubic feet per minute |
| ASTM | American Society for Testing and Materials |
| BACT | Best Available Control Technology |
| BHP | brake horsepower |
| Btu | British thermal units |
| CAA | Clean Air Act |
| CAM | Compliance Assurance Monitoring |
| CatOx | catalytic oxidation |
| CEMS | continuous emission monitoring systems |
| cfm | cubic feet per minute |
| CFR | Code of Federal Regulations |
| CI | compression ignition |
| CMS | continuous monitoring systems |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | $CO_2$ equivalent emissions |
| COMS | continuous opacity monitoring systems |
| CT | combustion turbine |
| CT1 | combustion turbine and duct burner |
| DAHS | data acquisition and handling system |
| DEQ | Idaho Department of Environmental Quality |
| dscf | dry standard cubic feet |
| EPA | United States Environmental Protection Agency |
| g | grams |
| gal | gallons |
| GHG | greenhouse gases |
| gph | gallons per hour |
| gpm | gallons per minute |
| gr | grains (1 lb = 7,000 grains) |
| HAP | hazardous air pollutants |
| HHV | higher heating value |
| HP | horsepower |
| hr | hours |
| hr/yr | hours per 12 consecutive calendar month period |
| HRSG | heat recovery steam generating unit |
| ICE | internal combustion engines |
| ID No. | identification number |
| IDAPA | a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act |
| J | Joules |
| kW | kilowatts |
| L | liters |
| lb | pounds |
| MACT | Maximum Achievable Control Technology |
| mg | milligrams |
| MMBtu | million British thermal units |
| MM lb/yr | million pounds per 12 consecutive calendar month period |
| MRRR | Monitoring, Recordkeeping and Reporting Requirements |
| MW | megawatts of electrical output |
| MWh | megawatt-hours |
| NAAQS | National Ambient Air Quality Standards |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| ng | nanograms |

| | |
|---|---|
| $NH_3$ | ammonia |
| NMHC | non-methane hydrocarbons |
| No. | number |
| NO | nitric oxide |
| $NO_x$ | nitrogen oxides |
| $NO_2$ | nitrogen dioxide |
| NSPS | New Source Performance Standards |
| O&M | operation and maintenance |
| $O_2$ | oxygen |
| PM | particulate matter |
| $PM_{2.5}$ | particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers |
| $PM_{10}$ | particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers |
| ppm | parts per million by volume |
| ppmw | parts per million by weight |
| PSD | Prevention of Significant Deterioration |
| PTC | permit to construct |
| PTE | potential to emit |
| QA | quality assurance |
| QC | quality control |
| RICE | reciprocating internal combustion engines |
| Rules | Rules for the Control of Air Pollution in Idaho |
| scf | standard cubic feet |
| SCR | selective catalytic reduction |
| SIP | State Implementation Plan |
| $SO_2$ | sulfur dioxide |
| TAP | toxic air pollutants |
| TDS | total dissolved solids |
| T1 | Tier I operating permit |
| T/yr | tons per 12 consecutive calendar month period |
| ULSD | ultra-low-sulfur diesel |
| U.S.C. | United States Code |
| VOC | volatile organic compounds |

## 2. FACILITY INFORMATION

### 2.1 Facility Description

The Idaho Power Company - Langley Gulch Power Plant operates as a one-on-one, combined-cycle plant, consisting of a natural gas-fired combustion turbine and a steam turbine. The combustion turbine is equipped with a heat recovery steam generator, which uses the exhaust heat to produce steam for the steam turbine. Supplemental natural gas duct firing within the HRSG provides additional heat in the exhaust gases, which increases steam production and steam turbine output for peak loads.

Ancillary equipment includes a diesel-fired emergency generator, a diesel-fired fire pump, a wet cooling tower, and three dry chemical storage silos. Dry chemicals for cooling water treatment may include magnesium oxide, soda ash, and lime.

### 2.2 Facility Permitting History

The following permitting history information is the comprehensive permitting history of all underlying applicable permits issued to this facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as "active and in effect" (A) or "superseded" (S).

**Table 2.1 Summary of Permitting History**

| Issue Date | Permit Number | Project | Description | Status |
|---|---|---|---|---|
| June 25, 2010 | P-2009.0092 | Initial PTC | Initial PSD PTC for a power plant and ancillary equipment. | S |
| August 14, 2013 | P-2009.0092 PROJ 61199 | Revised PTC | Revised PTC P-2009.0092 (6/25/10) equipment nameplate information and permit limits, including hours of operation and flow rate limits. | A |

## 3. APPLICATION SCOPE AND CHRONOLOGY

### 3.1 Application Scope

This permit is a revision of an existing PTC. The applicant has proposed to:

- Revise equipment nameplate information for the dry chemical storage silos, emergency generator, and emergency generator and fire pump engines.
- Replace the annual operating hours limit with an annual fuel usage limit for the combustion turbine and duct burner.
- Increase the annual hours of operation for the fire pump engine to meet maintenance and testing obligations.
- Increase the cooling tower flow rate limit.
- Install and operate above-ground fuel storage tanks.

### 3.2 Application Chronology

**Table 3.1 Summary of Application Chronology**

| Date | Description |
|---|---|
| March 11, 2013 | DEQ received a Tier I permit application (2013AAG289), which included revisions to equipment information and the emissions inventory. |
| March 20, 2013 | DEQ determined that the Tier I application was incomplete (2013AAG294). Additional information was requested to address equipment vendor changes. |
| April 3, 2013 | DEQ received supplemental information (2013AAG453), which included a preliminary applicability analysis concerning equipment vendor changes, and provided a schedule for submitting the remaining information requested in the incompleteness letter. |
| April 9, 2013 | DEQ determined that the Tier I application was complete (2013AAG295). |
| April 30, 2013 | DEQ received supplemental information (2013AAG702), including a complete applicability analysis addressing equipment vendor changes and a request (application) to revise PTC limits, along with copies of CEMS methodology, QA/QC plans, and the O&M manual. |
| May 8, 2013 | DEQ received a PTC application fee. |
| May 15, 2013 | DEQ made available the draft PTC and supporting documents for peer and regional office review. |
| May 20, 2013 | DEQ made available the draft PTC and supporting documents for applicant review (2013AAG712[v1], 2013AAG711[v1]). |
| May 30, 2013 | DEQ received comments from the applicant regarding the draft PTC and supporting documents (2013AAG847). |
| June 5, 2013 | DEQ determined that the PTC application was incomplete (2013AAG858). Estimates of ambient concentrations were requested to verify compliance with applicable ambient air quality standards. |
| June 21, 2013 | DEQ received supplemental information (2013AAG1038), including an ambient air quality compliance demonstration. |
| June 26 – July 11, 2013 | DEQ provided an opportunity to request a public comment period on the PTC application and proposed PTC permitting action. |
| July 10, 2013 | DEQ made available the revised draft PTC and supporting documents for peer and regional office review. |
| July 26, 2013 | DEQ made available the revised draft PTC and supporting documents for applicant review (2013AAG712[v2], 2013AAG711[v2]). |
| August 14, 2013 | DEQ issued the final PTC permit (2013AAG712[v3], 2013AAG711[v3]). |

# 4. EMISSIONS UNITS AND EMISSION INVENTORIES

## 4.1 Emissions Units and Control Equipment

Table 4.1 lists the emissions units and control equipment associated with the Idaho Power Company - Langley Gulch Power Plant.

**Table 4.1 Regulated Sources**

| Source Description | | Control Equipment Description |
|---|---|---|
| Combustion turbine and duct burner (CT1) | | Dry low $NO_x$ combustors<br>Selective catalytic reduction system<br>Catalytic oxidation system<br>Good combustion practices |
| *Combustion turbine (CT)* | | |
| Manufacturer: | Siemens | |
| Model: | SGT6-5000F | |
| Configuration: | 1x1 combined cycle | |
| Manufacture date: | 2010 | |
| Maximum capacity: | 2,134 MMBtu/hr [(a)] | |
| Maximum energy output: | ≥190 MW | |
| Fuel: | natural gas | |
| Fuel consumption: | 793.1 MM lb/yr [(b)] | |
| *Duct burner* | | |
| Manufacturer: | Hamworthy Peabody | |
| Manufacture date: | 2010 | |
| Maximum capacity: | 241.28 MMBtu/hr [(a)] | |
| Fuel: | natural gas | |
| Fuel consumption: | 793.1 MM lb/yr [(b)] | |
| Emergency generator engine | | EPA Tier 2 technologies<br>Good combustion practices |
| Manufacturer: | Caterpillar | |
| Model: | C27 | |
| Manufacture date: | 2011 | |
| Maximum capacity: | 1,214 BHP (750 kW)<br>2.25 L/cylinder | |
| Maximum operation: | 4 hr/day and 60 hr/yr [(c)] | |
| Fuel: | ultra-low sulfur diesel | |
| Fuel consumption: | 53.6 gph | |
| Fire pump engine | | EPA Tier 3 technologies<br>Good combustion practices |
| Manufacturer: | Cummins | |
| Model: | CFP9E-F30 | |
| Manufacture date: | 2010 | |
| Maximum capacity: | 305 BHP (235 kW)<br>1.48 L/cylinder | |
| Maximum operation: | 2 hr/day and 40 hr/yr [(c)] | |
| Fuel: | ultra-low sulfur diesel | |
| Fuel consumption: | 15.8 gph | |
| Cooling tower | | Drift eliminators<br>Good operating practices |
| Manufacturer: | GEA | |
| Model: | 7-cell, counterflow wet | |
| Manufacture date: | 2010 | |
| Maximum water flow: | 76,151 gpm | |
| Maximum TDS: | 5,000 mg/L | |
| Dry chemical storage silos (3) | | Bin vent filters<br>Good operating practices |
| Manufacturer: | Silosafe | |
| Manufacture date: | 2010 | |
| Maximum capacities: | 6500, 2200, and 2090 $ft^3$ | |
| Maximum loading operation: | 2 hr/day and 48 hr/yr per silo | |
| Above-ground fuel storage tanks (2) | | Lids or other appropriate closure |
| Manufacture date: | 2013 | |
| Maximum capacity: | 250 gal each (diesel/gasoline) | |

a) At higher heating value (HHV), 100 percent load, and 0°F.
b) Combined fuel usage limit for the CT and duct burner.
c) For maintenance and testing activities.

## 4.2 Emission Inventories

Table 4.2 and Table 4.4 summarize the emission inventories of federally regulated criteria pollutant, hazardous air pollutant (HAP) pollutant, and greenhouse gas (GHG) emissions. Emissions are in tons per year (T/yr) and represent the facility-wide potential to emit.

Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design (IDAPA 58.01.01.006.86). Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Manufacturer performance guarantees and the use of the control equipment, fuels, and operational schedules listed in Table 4.1 were used in the development of the emission inventories. Refer to Appendix A – Emission Inventories for the emission estimates provided in the application.

**Table 4.2 Proposed Potential to Emit Criteria Pollutants [a]**

| | $NO_x$ | | CO | | VOC | | $PM_{2.5}$[b]/$PM_{10}$[c] | | $SO_2$ | | Pb | | GHG $CO_2e$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Emissions Units** | **lb/hr** | **T/yr[d]** | **lb/hr** | **T/yr[d]** | **lb/hr** | **T/yr[d]** | **lb/hr** | **T/yr[d]** | **lb/hr** | **T/yr[d]** | **lb/hr** | **T/yr[d]** | **T/yr[d]** |
| CT and duct burner[e] peak[f] | 20.10 | 88.0 | 12.24 | 278.10 | 7.01 | 74.90 | 12.55 | 49.46 | 3.41 | 13.44 | 0.02 | 0.05 | 1,055,941 |
| CT and duct burner[e] LL[g] | 452.78 | | 70.35 | | 18.91 | | | | | | | | |
| CT and duct burner[e] SU/SD[h] | 304.56 | | 2510.00 | | 186.60 | | | | | | | | |
| Emergency generator[i] | 12.80 | 0.39 | 7.00 | 0.21 | 0.80 | 0.02 | 0.40 | 0.01 | 0.01 | 0.01 | | | 42 |
| Fire pump[j] | 2.00 | 0.03 | 1.70 | 0.03 | 0.10 | 0.00 | 0.10 | 0.00 | 0.00 | 0.01 | | | 7 |
| Cooling tower[k] | | | | | | | 0.81 | 3.50 | | | | | |
| Dry chemical storage silos[l] | | | | | | | 0.13 | 0.01 | | | | | |
| Above-ground fuel storage tanks | | | | | 0.03 | 0.15 | | | | | | | |
| Paved roads[m] | | | | | | | 0.20 | 0.01 | | | | | |
| Unpaved roads[m] | | | | | | | 0.27 | 0.01 | | | | | |
| **Facility Totals** | **467.58** | **88.42** | **2518.70** | **278.35** | **187.53** | **75.07** | **14.46** | **53.00** | **3.42** | **13.47** | **0.02** | **0.05** | **1,055,990** |

a) Short-term (lb/hr) and annual (T/yr) emission estimates assumed the use of BACT and were based on daily and annual limits on hours of operation. Emission estimates were derived from the application and statement of basis for PTC No. P-2009.0092, issued June 25, 2010, and from updated estimates provided in the application.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
d) Tons per any 12 consecutive calendar month period, calculated as a 12-month rolling total.
e) Annual totals assume a maximum fuel usage of 793.1 MM lb/yr, which accounts for continuous duct-firing under full-load for 6,902 hours, 253 hot startups, 45 warm startups, 7 cold startups, and 305 shutdowns annually.
f) At steady-state and ≥ 60% of full-load operating conditions.
g) At steady-state and < 60% of full-load operating conditions.
h) At startup or shutdown operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).
i) Limited to 4 hr/day and 60 hr/yr operation for maintenance and testing purposes.
j) Limited to 2 hr/day and 40 hr/yr operation for maintenance and testing purposes.
k) Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 mg/L and a circulating flow rate of 76,151 gpm.
l) Total emissions from the dry chemical storage silos. Annual totals assume each silo is loaded up to 48 hours per year.
m) Fugitive emission sources.

### Table 4.3 Emission Increases in Potential to Emit Criteria Pollutants [(a)]

| Emissions Units | $NO_x$ | | CO | | VOC | | $PM_{2.5}$[(b)]/$PM_{10}$[(c)] | | $SO_2$ | | Pb | | GHG $CO_2e$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | lb/hr | T/yr[(d)] | lb/hr | T/yr[(d)] | lb/hr | T/yr[(d)] | lb/hr | T/yr[(d)] | lb/hr | T/yr[(d)] | lb/hr | T/yr[(d)] | T/yr[(d)] |
| CT and duct burner[(e)] peak[(f)] | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0 |
| CT and duct burner[(e)] LL[(g)] | 0.00 | | 0.00 | | 0.00 | | | | | | | | |
| CT and duct burner[(e)] SU/SD[(h)] | 0.00 | | 0.00 | | 0.00 | | | | | | | | |
| Emergency generator[(i)] | 1.20 | 0.04 | 0.70 | 0.02 | 0.07 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | | | 0 |
| Fire pump[(j)] | (0.10) | 0.00 | (0.10) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | | 0 |
| Cooling tower[(k)] | | | | | | | 0.14 | 0.59 | | | | | |
| Dry chemical storage silos[(l)] | | | | | | | 0.09 | 0.00 | | | | | |
| Above-ground fuel storage tanks | | | | | 0.03 | 0.15 | | | | | | | |
| Paved roads[(m)] | | | | | | | 0.00 | 0.00 | | | | | |
| Unpaved roads[(m)] | | | | | | | 0.00 | 0.00 | | | | | |
| **Emission Increases** | **1.20** | **0.04** | **0.70** | **0.02** | **0.10** | **0.15** | **0.27** | **0.59** | **0.00** | **0.00** | **0.00** | **0.00** | **0** |
| ***Modeling Threshold*** | ***0.20*** | ***1.20*** | ***15*** | | | | ***0.054/0.22*** | ***0.35*** | ***0.21*** | ***1.20*** | | | |
| ***NSR Significance*** | | ***40*** | | ***100*** | | ***40*** | | ***10/15*** | | ***40*** | | ***0.6*** | ***75,000*** |

a) Short-term (lb/hr) and annual (T/yr) emission estimates assumed the use of BACT and were based on daily and annual limits on hours of operation. Emission estimates were derived from the application and statement of basis for PTC No. P-2009.0092, issued June 25, 2010, and from updated estimates provided in the application.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
d) Tons per any 12 consecutive calendar month period, calculated as a 12-month rolling total.
e) Annual totals assume a maximum fuel usage of 793.1 MM lb/yr, which accounts for continuous duct-firing under full-load for 6,902 hours, 253 hot startups, 45 warm startups, 7 cold startups, and 305 shutdowns annually.
f) At steady-state and ≥ 60% of full-load operating conditions.
g) At steady-state and < 60% of full-load operating conditions.
h) At startup or shutdown operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).
i) Limited to 4 hr/day and 60 hr/yr operation for maintenance and testing purposes.
j) Limited to 2 hr/day and 40 hr/yr operation for maintenance and testing purposes.
k) Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 mg/L and a circulating flow rate of 76,151 gpm.
l) Total emissions from the dry chemical storage silos. Annual totals assume each silo is loaded up to 48 hours per year.
m) Fugitive emission sources.

Emission increases (Table 4.3 and Table 4.4) were proposed for the emergency generator, the cooling tower, the dry chemical storage silos, and the above-ground fuel storage tanks. The proposed emission increases of criteria pollutants for these sources combined (Table 4.3) was less than the significance level for PSD.

Greenhouse gases (GHG) were not considered regulated air pollutants with respect to the facility under the PSD program, as provided in 40 CFR 52.21(b)(49) and IDAPA 58.01.01.006.97.d, because the facility has not proposed a physical change or change in the method of operation that would result in an emissions increase of 75,000 T/yr $CO_2e$ or more.[1] Therefore, this project was not applicable to PSD program requirements.

[1] In accordance with 40 CFR 52.21(b)(49)(v)(b) and IDAPA 58.01.01.006.97.d, GHG shall be subject to regulation at an existing stationary source that emits or has the potential to emit equal to or greater than 100,000 T/yr $CO_2e$ (and equal to or greater than 100 T/yr on a mass basis), when such stationary source undertakes a physical change or change in the method of operation that will result in an emissions increase of 75,000 T/yr $CO_2e$ or more.

## Table 4.4 Potential to Emit HAP and TAP – PTE and Emission Increases

| Pollutant | Category TAP/HAP | Averaging Period | Screening Emission Level lb/hr | Emission Increase lb/hr[a] | PTE lb/hr[a] | HAP PTE T/yr[e] |
|---|---|---|---|---|---|---|
| 1,3-Butadiene | HAP, 586 TAP[d] | Annual [b] | 2.40E-05 | 1.96E-08 | 8.26E-04 | 3.62E-03 |
| 2-Methylnaphthalene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | | 5.24E-06 | |
| 3-Methylcholanthrene | HAP, 586 TAP[d] | Annual [b] | 2.50E-06 | | 3.93E-07 | |
| 7,12-Dimethylbenz(a)anthracene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | | 3.50E-06 | |
| Acenaphthene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.08E-08 | 6.46E-07 | |
| Acenaphthylene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 2.25E-08 | 9.08E-07 | |
| Acetaldehyde | HAP, 586 TAP[d] | Annual [b] | 3.00E-03 | 4.38E-07 | 7.68E-02 | 3.36E-01 |
| Acrolein | HAP, 585 TAP[c] | 24-hour [a] | 1.70E-02 | 1.26E-06 | 1.39E-02 | 5.38E-02 |
| Ammonia | 585 TAP[c] | 24-hour [a] | 1.20E+00 | | 1.86E+01 | |
| Anthracene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 3.59E-09 | 6.02E-07 | |
| Arsenic | HAP, 586 TAP[d] | Annual [b] | 1.50E-06 | | 4.37E-05 | 1.91E-04 |
| Barium | 585 TAP[c] | 24-hour [a] | 3.30E-02 | | 1.07E-03 | |
| Benzene | HAP, 586 TAP[d] | Annual [b] | 8.00E-04 | 4.36E-04 | 2.39E-02 | 1.05E-01 |
| Benzo(a)pyrene | HAP, 586 TAP[d,f] | Annual [b] | 2.00E-06 | 6.49E-10 | 2.77E-07 | |
| Benzo(g,h,i)perylene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.45E-09 | 2.94E-07 | |
| Beryllium | HAP, 586 TAP[d] | Annual [b] | 2.80E-05 | | 2.62E-06 | 1.15E-05 |
| Cadmium | HAP, 586 TAP[d] | Annual [b] | 3.70E-06 | | 2.40E-04 | 1.05E-03 |
| Chromium | HAP, 585 TAP[c] | 24-hour [a] | 3.30E-02 | | 3.40E-04 | 3.06E-04 |
| Cobalt | HAP, 585 TAP[c] | 24-hour [a] | 3.30E-03 | | 2.04E-05 | 8.04E-05 |
| Copper | 585 TAP[c] | 24-hour [a] | 1.30E-02 | | 2.06E-04 | |
| Cyclohexane | HAP, 585 TAP[c] | 24-hour [a] | 6.77E+01 | 4.57E-05 | 4.57E-05 | |
| Dichlorobenzene (o- and 1,4-) | HAP, 585 TAP[c] | 24-hour [a] | 2.00E+01 | | 2.91E-04 | 1.15E-03 |
| Ethyl alcohol | HAP, 585 TAP[c] | 24-hour [a] | 1.25E+02 | 5.48E-04 | 5.48E-04 | |
| Ethyl benzene | HAP, 585 TAP[c] | 24-hour [a] | 2.90E+01 | | 6.83E-02 | 2.69E-01 |
| Fluoranthene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 3.81E-09 | 9.12E-07 | |
| Fluorene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 4.22E-08 | 1.49E-06 | |
| Formaldehyde | HAP, 586 TAP[d] | Annual [b] | 5.10E-04 | 7.61E-07 | 1.38E+00 | 6.04E+00 |
| Hexane | HAP, 585 TAP[c] | 24-hour [a] | 1.20E+01 | | 4.37E-01 | 1.72E+00 |
| Manganese | HAP, 585 TAP[c] | 24-hour [a] | 6.70E-02 | | 9.22E-05 | 3.64E-04 |
| Mercury | HAP, 585 TAP[c] | 24-hour [a] | 1.00E-03 | | 6.31E-05 | 2.49E-04 |
| Molybdenum | 585 TAP[c] | 24-hour [a] | 3.33E-01 | | 2.67E-04 | |
| Naphthalene | 585 TAP[c] | 24-hour [a] | 3.33E+00 | 3.23E-07 | 4.03E-03 | |
| Naphthalene (as PAH) | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 7.60E-06 | 2.94E-03 | |
| Nickel | HAP, 586 TAP[d] | Annual [b] | 2.75E-05 | | 4.59E-04 | 2.01E-03 |
| Nitrous oxide | 585 TAP[c] | 24-hour [a] | 6.00E+00 | | 6.93E+00 | |
| Pentane | 585 TAP[c] | 24-hour [a] | 1.18E+02 | | 6.31E-01 | |
| Phenanthrene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.03E-07 | 6.04E-06 | |
| Propylene oxide | HAP, 585 TAP[c] | 24-hour [a] | 3.20E+00 | 1.70E-04 | 6.21E-02 | 2.72E-01 |
| POM (7-PAH Group)[f] | HAP, 586 TAP[d,f] | Annual [b] | 2.00E-06 | | 2.74E-06 | |
| Pyrene | HAP, 586 TAP[d,f] | Annual [b] | 9.10E-05 | 1.04E-08 | 1.32E-06 | |
| Selenium | HAP, 585 TAP[c] | 24-hour [a] | 1.30E-02 | | 5.83E-06 | 2.30E-05 |
| Sulfuric acid mist | 585 TAP[c] | 24-hour [a] | 6.70E-02 | | 2.61E-01 | |
| Toluene | HAP, 585 TAP[c] | 24-hour [a] | 2.50E+01 | 2.58E-04 | 2.81E-01 | 1.10E+00 |
| 1,2,4-Trimethylbenzene | HAP, 585 TAP[c] | 24-hour [a] | 8.20E+00 | 1.03E-05 | 1.03E-05 | |
| Vanadium | 585 TAP[c] | 24-hour [a] | 3.00E-03 | 1.27E-05 | 5.71E-04 | |
| Xylenes | HAP, 585 TAP[c] | 24-hour [a] | 2.90E+01 | 5.38E-05 | 1.39E-01 | 5.38E-01 |
| Zinc | 585 TAP[c] | 24-hour [a] | 3.33E-01 | | 7.04E-03 | |
| Total POM | HAP | Annual [b] | see above[f] | | 6.89E-03 | 3.02E-02 |
| **Individual HAP** | | | | | | 6.04 |
| **Total HAP** | | | | | | 12.28 |

a) Uncontrolled average emission rate in pounds per hour is the maximum estimated hourly average.
b) Controlled average emission rate in pounds per hour is an annual average, based on the proposed annual operating schedule and annual limits.
c) Non-carcinogenic substance listed in IDAPA 58.01.01.585.
d) Carcinogenic substance listed in IDAPA 58.01.01.586.
e) Tons per 12 consecutive calendar month period.
f) Polyaromatic hydrocarbons (PAH) and polycyclic organic matter (POM) are defined in IDAPA 58.01.01.586.

### 4.3 Ambient Air Quality Impact Analyses

With the exception of $NO_x$, $PM_{2.5}$, and $PM_{10}$, the estimated emission increases from this project (Table 4.3 and Table 4.4) were below applicable screening emission levels (EL) and published DEQ modeling thresholds established in IDAPA 58.01.01.585-586 and in the State of Idaho Air Quality Modeling Guideline.[2]

Because uncontrolled TAP emission increases were less than or equal to applicable screening emission levels, no further procedures for demonstrating preconstruction compliance was required, in accordance with IDAPA 58.01.01.210.05. An evaluation of impacts to ambient air quality from the project resulting from $NO_x$, $PM_{2.5}$, $PM_{10}$, and CO emission increases was provided by the applicant, and verification modeling analyses was conducted by DEQ. Refer to Appendix B – Ambient Air Quality Impact Analysis for a summary of results. Refer to the Emission Inventories section and to Appendix A – Emission Inventories for the emission estimates provided in the application.

The applicant has demonstrated to DEQ's satisfaction that emissions from the proposed permit revision will not cause or significantly contribute to a violation of any ambient air quality standard.

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2 Criteria pollutant modeling thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, rev. 2, July 2011.

## 5. REGULATORY REVIEW

### 5.1 Attainment Designation (40 CFR 81.313)

The facility is located in Payette County, which is designated as attainment or unclassifiable for $PM_{2.5}$, $PM_{10}$, $SO_2$, $NO_2$, CO, and ozone, and is located within Air Quality Control Region (AQCR) 63. There are no Class I areas within 10 kilometers of the proposed facility. Refer to 40 CFR 81.313 for additional information.

### 5.2 Permit to Construct (IDAPA 58.01.01.201)

An application was submitted to revise the permit to construct. Therefore, this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

### 5.3 Tier II Operating Permit (IDAPA 58.01.01.401)

An application was submitted to revise the permit to construct, and an optional Tier II operating permit was not requested. Therefore, the procedures of IDAPA 58.01.01.400-410 were not applicable to this permitting action.

### 5.4 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The proposed facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because the facility has the potential to emit 100 tons per year or more of CO (278.35 T/yr).

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr, it is a designated facility as defined in IDAPA 58.01.01.006, and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

The initial Tier I operating permit action is being processed concurrently with this permitting action. Refer to the Statement of Basis to Tier I Operating Permit No. T1-2013.0017 PROJ 61165 for additional discussion concerning Title V program requirements and classification.

### 5.5 PSD Classification (40 CFR 52.21)

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input (designated facility) and has the potential to emit 100 tons per year or more of CO (278.35 T/yr), it is classified as an existing major stationary source as defined in §52.21(b)(1)(i)(a) and in accordance with IDAPA 58.01.01.205.01.

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr, it is a designated facility as defined in IDAPA 58.01.01.006, and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

*IDAPA 58.01.01.205....................................PERMIT REQUIREMENTS FOR NEW MAJOR FACILITIES OR MAJOR MODIFICATIONS IN ATTAINMENT OR UNCLASSIFIABLE AREAS.*

*40 CFR 52.21 ..............................................Prevention of significant deterioration of air quality.*

*40 CFR 52.21(a)(2) .....................................Applicability procedures.*

*In accordance with §52.21(a)(2)(i), Prevention of Significant Deterioration (PSD) requirements apply to the construction of any new major stationary source or any project at an existing major stationary source in an area designated as attainment or unclassifiable.*

This permit revision request was proposed for an existing major stationary source in an area designated as attainment or unclassifiable. Refer to the Attainment Designation (40 CFR 81.313) section for additional information.

*In accordance with §52.21(a)(2)(ii), the requirements of §52.21(j) through (r) apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as otherwise provided.*

This permit revision was not considered a major modification as defined in §52.21(b)(2)(i), because it was not predicted to result in a significant net emissions increase as determined in accordance with §52.21(b)(40). The changes in potential to emit resulting from this permitting action for each and all of the affected emission sources were predicted to be less than the significant levels as defined in §52.21(b)(23)(i) and as provided above in Table 4.3.

Greenhouse gases (GHG) were not considered regulated air pollutants with respect to the facility under the PSD program, as provided in 40 CFR 52.21(b)(49) and IDAPA 58.01.01.006.97.d, because the facility has not proposed a physical change or change in the method of operation that would result in an emissions increase of 75,000 T/yr CO2e or more. In addition, §52.21(j) through (r)(5) were not determined to be applicable to this project. Additional information concerning this determination is provided in the Emission Inventories section regarding the emissions increase calculations.

### 5.6 NSPS Applicability (40 CFR 60)

The facility is subject to 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and Subpart A – General Provisions.

The CT, HRSG, and HRSG duct burner are affected sources subject to Subpart KKKK, because the construction dates were after February 18, 2005.

The emergency generator and fire pump are affected sources subject to 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, because the construction dates were after June 12, 2006.

In accordance with 40 CFR 60.4200(a)(2)(i), the CT is exempt from the requirements of Subpart GG, and the HRSG and duct burner are exempt from the requirements of 40 CFR 60, Subparts Da, Db, and Dc – Standards of Performance for Steam Generating Units, because the CT, HRSG, and duct burner are regulated under Subpart KKKK.

Refer to Table 4.1 for dates of manufacture for each emissions unit.

### 5.7 NESHAP Applicability (40 CFR 61)

The facility and emission sources are not subject to NESHAP requirements in 40 CFR 61.

### 5.8 MACT Applicability (40 CFR 63)

The stationary RICE (emergency generator and fire pump) are area sources subject to 40 CFR 63, Subpart ZZZZ because they commenced construction on or after June 12, 2006 (2010-2011). Because these sources are subject to regulation under 40 CFR 60, Subpart IIII, no further requirements are applicable under 40 CFR 63, Subpart ZZZZ.

The facility is not subject to 40 CFR 63, Subpart Q – NESHAP for Industrial Process Cooling Towers or to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines, because the facility was not proposed as a major source of HAP emissions.

### 5.9 Permit Conditions Review

This section describes only those permit conditions that have been added, revised, modified or deleted in this permitting action. Refer to the Statement of Basis to Tier I Operating Permit No. T1-2013.0017 PROJ 61165 for additional discussion concerning permit conditions which have not otherwise been addressed.

Because the initial Tier I operating permit action is being processed concurrently with this permitting action, permit conditions have been renumbered for consistency with Tier I operating permit formatting to facilitate incorporation, including reserving permit conditions (Permit Conditions 3.14, and 3.24 through 3.26) for Tier I conditions. Refer to the Emission Inventories section and to Appendix A – Emission Inventories for the emission estimates provided in the application.

Table 2.1 (Revised Permit Condition 2)

2. *The emission sources regulated by this permit are listed in the following table:*

**REGULATED EMISSION POINT SOURCES**

| ***Emissions Unit Descriptions*** | | ***Control Equipment Descriptions*** |
|---|---|---|
| *Combustion turbine (CT)* | | |
| *Manufacturer:* | *Siemens* | |
| *Model:* | *SGT6-5000F* | |
| *Configuration:* | *1X1 combined cycle* | |
| *Manufacture date:* | *2010* | |
| *Nominal output:* | *269 MW* | |
| *Maximum capacity:* | *2,134 MMBtu/hr*[a] | |
| *Maximum operation:* | *7,884 hr/yr* | *Dry low $NO_x$ combustors* |
| *Fuel:* | *natural gas* | *Selective catalytic reduction system* |
| *Fuel consumption:* | *2,146,600 scf/hr* | *Catalytic oxidation system* |
| | | *Good combustion practices* |
| *Duct burner* | | |
| *Manufacturer:* | *Hamworthy Peabody* | |
| *Manufacture date:* | *2010* | |
| *Maximum capacity:* | *241.28 MMBtu/hr*[a] | |
| *Maximum operation:* | *7,884 hr/yr* | |
| *Fuel:* | *natural gas* | |
| *Fuel consumption:* | *242,739 scf/hr* | |
| *Emergency generator engine* | | |
| *Manufacturer:* | *Cummins* | |
| *Model:* | *DQFAA* | |
| *Manufacture date:* | *2009* | |
| *Maximum capacity:* | *1,102 BHP (750 kW)* | *EPA Tier 2 technologies* |
| | *2.54 L/cylinder* | *Good combustion practices* |
| *Maximum operation:* | *4 hr/day and 60hr/yr*[b] | |
| *Fuel:* | *diesel* | |
| *Fuel consumption:* | *51.3 gph* | |
| *Fire pump engine* | | |
| *Manufacturer:* | *John Deere* | |
| *Model:* | *JU6H-UFAD98* | |
| *Manufacture date:* | *2009* | |
| *Maximum capacity:* | *315 HP (235 kW)* | *EPA Tier 3 technologies* |
| | *1.14 L/cylinder, 1760 rpm* | *Good combustion practices* |
| *Maximum operation:* | *1 hr/day and 30hr/yr*[b] | |
| *Fuel:* | *diesel* | |
| *Fuel consumption:* | *15 gph* | |
| *Cooling tower* | | |
| *Manufacturer:* | *GEA Power Cooling* | |
| *Model:* | *7-cell, counterflow wet* | |
| *Manufacture date:* | *2010* | *Drift eliminators* |
| *Maximum water flow:* | *63,200 gpm* | *Good operating practices* |
| *Maximum operation:* | *8,760 hr/yr* | |
| *Maximum TDS:* | *5,000 mg/L* | |
| *Dry chemical storage silos (no more than 6)* | | |
| *Manufacturer:* | *Seneca* | |
| *Manufacture date:* | *2010* | *Bin vent filters* |
| *Maximum capacity:* | *4,072 $ft^3$ (10,500 gal)* | *Good operating practices* |
| *Maximum loading operation:* | *2 hr/day and 24 hr/yr per silo* | |

*a) At higher heating value (HHV), 100 percent of peak load, and 0°F.*
*b) For maintenance and testing activities.*

The Regulated Emission Point Sources Table was revised to reflect changes in nameplate information for the emergency generator, the fire pump, and the dry chemical storage silos. Above-ground fuel storage tanks were also added. Refer to the Emission Inventories section for a discussion of the emission increases associated with these changes.

Removed Permit Condition 68

68. *NSPS 40 CFR 60, Subpart KKKK – $NO_x$ CEMS Performance Test Methods*

*The initial performance test required under 40 CFR 60.8 (Permit Condition 28) shall be performed in the following manner or as provided in 40 CFR 60.4400, in accordance with 40 CFR 60.4405:*

- *Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs;*
- *For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit;*
- *Use the test data both to demonstrate compliance with the applicable $NO_x$ emission limit under 40 CFR 60.4320 (Permit Condition 37) and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.4335.*
- *Compliance with the applicable emission limit in 40 CFR 60.4320 (Permit Condition 37) is achieved if the arithmetic average of all of the $NO_x$ emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.*

Because the initial $NO_x$ performance test was completed,[3] initial testing requirements were considered satisfied and were removed. Ongoing compliance with $NO_x$ CEMS MRRR is required.

Removed Permit Condition 85

85. *NSPS 40 CFR 60, Subpart IIII – Notification, Reports, and Records*

- *The permittee is not required to submit an initial notification as required in 40 CFR 60.7(a)(1) for the emergency generator engine and the fire pump engine, in accordance with 40 CFR 60.4214(b).*
- *If the emergency generator engine or the fire pump engine are equipped with a diesel particulate filter, the permittee shall keep records of any corrective action taken after the backpressure monitor has notified the permittee that the high backpressure limit of the engine is approached, in accordance with 40 CFR 60.4214(c).*

Because a particulate filter is not required for the emergency generator or fire pump engine to comply with the applicable emission standards under NSPS Subpart IIII,[4] and because initial notification is a non-applicable requirement, this requirement has been removed. A high-level citation referencing these requirements was retained in Permit Condition 5.9.

Permit Conditions 3.15 – 3.16 (Revised Permit Conditions 16 – 18)

16. *Within 60 days after initial startup of the combustion turbine (CT), the permittee shall develop and submit to DEQ an Operation and Maintenance (O&M) manual for review and comment at the address provided (Permit Condition 31). Any changes to the O&M manual shall be submitted to DEQ for review and comment within 15 days of the change.*
17. *The O&M manual shall describe for each of the control equipment described in the Regulated Emission Point Sources Table (Permit Condition 2) procedures that will be followed to ensure compliance with the BACT emission limits (Permit Condition 33), the BACT secondary emission limits (Permit Conditions 34 and 35), the BACT work practices (Permit Conditions 43, 79, 89, and 94), the ammonia injection flow rate limit (Permit Condition 49), the control equipment maintenance and operation general provision (Permit Condition 96), and manufacturer's specifications. The O&M manual shall be a permittee developed document based upon, but independent from, the manufacturer supplied operating manual(s).*
18. *The permittee shall operate the control equipment in accordance with the O&M manual. The procedures specified in the O&M manual are incorporated by reference into this permit and are enforceable permit*

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3 Tables 4.3 and 4.4 of "Source Emissions Testing Report, Idaho Power Company," Air Pollution Testing, Inc., July 31, 2012 (2012AAI1607).

4 Reply and comments concerning the revised draft permit (Permit Conditions 5.9 and 5.13), Idaho Power Company, received August 7, 2013 (2013AAG1365).

*conditions. The O&M manual and copies of any manufacturer's manual(s) and recommendations shall remain on site at all times and shall be made available to DEQ representatives upon request.*

Because the O&M manuals were developed, requirements to develop these documents were considered satisfied and were removed.[5] Ongoing maintenance of, and compliance with, these documents is required.

Permit Condition 4.7 (Revised Permit Condition 38)

38. *NSPS 40 CFR 60, Subpart KKKK – $SO_2$ Emission Limits*

*The permittee shall comply with one of the options specified in 40 CFR 60.4330(a), in accordance with 40 CFR 60.4330(a):*

- *The permittee shall not cause to be discharged into the atmosphere from the subject stationary CT any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or*
- *The permittee shall not burn in the subject stationary CT any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input.*

The permittee has elected to comply with the fuel sulfur content-based compliance option to demonstrate compliance with the $SO_2$ emission limit under NSPS Subpart KKKK. For clarification purposes, the lb/MWh form of the $SO_2$ emission limit has been removed.

Permit Conditions 4.9, 4.19, and 4.32 (Revised Permit Condition 40, 49, and 62)

40. *Ammonia Slip Emission Limit*

*The emissions from the HRSG Stack shall not exceed 5 parts of ammonia per million parts of gas by volume (ppm), calculated as a 3-hour rolling average, on a dry basis and corrected to 15% $O_2$ concentration, to ensure compliance with the control equipment maintenance and operation general provision (Permit Condition 96).*

49. *Ammonia Injection Flow Rate*

*The hourly average ammonia injection flow rate shall not exceed 1.03 gallons per minute (gpm), to ensure compliance with the ammonia slip emission limit (Permit Condition 40).*

62. *Ammonia Injection Flow Rate*

*Each calendar day that the CT is operated, the permittee shall monitor and record the ammonia injection flow rate to ensure compliance with the ammonia injection flow rate limit (Permit Condition 49).*

- *If a continuous monitoring system is used to monitor the ammonia injection flow rate, the average hourly ammonia injection flow rate (in gpm) shall be calculated and recorded to demonstrate compliance with the ammonia injection flow rate limit (Permit Condition 49).*
- *The monitoring and calculation methodology for the ammonia injection flow rate shall be described in the O&M manual (Permit Conditions 16 through 18).*

The permittee requested revision of the ammonia emission limit and ammonia flow rate limit to allow up to 24-hour averaging of hourly measurements, for consistency with the acceptable ambient concentration averaging period allowed for ammonia under IDAPA 58.01.01.585.

Permit Condition 4.17 and 4.31 (Revised Permit Conditions 50 and 63)

50. *Hours of Operation*

- *Operation of the CT shall not exceed 7,884 hours in any consecutive 12 calendar month period.*
- *Operation of the duct burner shall not exceed 7,884 hours in any consecutive 12 calendar month period.*

[5] Copies of these documents are included in Appendix B to Tier I Operating Permit No. T1-2013.0017 PROJ 61165 (2013AAG590).

63. *Hours of Operation Monitoring*

*Each calendar month, the permittee shall monitor and record the following information to ensure compliance with the hours of operation limits (Permit Condition 50):*

- *The operating hours of the CT, in hours per calendar month and in hours per consecutive 12 calendar month period; and*
- *The operating hours of the duct burner, in hours per calendar month and in hours per consecutive 12 calendar month period.*

The permittee requested revision of the hours of operation limit, by replacement with an annual fuel usage limit.[6] Corresponding monitoring requirements were similarly revised.

Permit Condition 4.21 (Revised Permit Condition 52)

52. *$NO_x$ CEMS Monitoring for BACT and Annual Limits*

*For the purposes of demonstrating compliance with the $NO_x$ BACT emission limit (Permit Condition 33), the $NO_x$ BACT secondary emission limits (Permit Conditions 34 and 35), and the $NO_x$ annual emission limit (Permit Condition 36), the permittee shall comply with the following requirements:*

- *Each $NO_x$ CEMS shall meet the requirements for CEMS set forth in 40 CFR 60, Subpart A (Permit Condition 28).*
- *Startup, shutdown, and low-load events shall be monitored in accordance with the startup, shutdown, and low-load events monitoring requirement (Permit Condition 51).*
- *Emissions shall be monitored according to the $NO_x$ CEMS monitoring excess emissions requirement (Permit Condition 56). Hourly, monthly, and annual averages shall be calculated using CEMS totals and excess emissions shall be assessed according to the procedures in the $NO_x$ CEMS monitoring excess emissions for BACT and annual limits requirement (Permit Condition 53). Electronic archives are an acceptable form of documentation for recordkeeping.*
- *Monitor downtime shall be defined as set forth in 40 CFR 60.4380(b)(2) (Permit Condition 70).*
- *Excess emissions and monitor downtime shall be reported according to the procedures set forth in 40 CFR 60, Subpart A (Permit Condition 28) and in accordance with the excess emissions procedures and requirements (Permit Conditions 19 through 26).*
- *A test protocol shall be submitted to DEQ for each certification and recertification of the CEMS. Each test protocol shall be submitted to DEQ for approval at least 30 days prior to the test date. Following the approval of the initial test protocol, the permittee may waive this reporting requirement by providing a certified statement that each recertification test will be performed in the same manner as a test protocol previously approved for the CEMS.*
- *Within 180 days of permit issuance, the permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval, addressing the methods used to quantify emission concentrations and emission rates from the HRSG stack and the methods used to ensure data quality. The protocol must be sufficiently detailed to allow DEQ to verify emissions rate estimates for purposes of determining compliance. The permittee shall maintain the DEQ-approved protocols onsite at all times the CT is operated.*
- *Records of all CEMS emission data, calibration reports, excess emissions and monitor downtime reports, and maintenance performed shall be maintained in accordance with the monitoring and recordkeeping general provision (Permit Condition 103).*

Because the CEMS methodology and quality assurance and quality control (QA/QC) protocols were developed, requirements to develop these documents were considered satisfied and were removed.[7] Ongoing maintenance of, and compliance with, these documents is required.

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[6] Section 4.2.2 of "Tier I Permit Application Supplemental Information," Idaho Power Company, received April 30, 2013 (2013AAG702).

[7] Copies of these documents are included in Appendix B to Tier I Operating Permit No. T1-2013.0017 PROJ 61165 (2013AAG590).

Permit Condition 4.24 (Revised Permit Condition 55)

55. *NSPS 40 CFR 60, Subpart KKKK – $NO_x$ CEMS Monitoring Option*

*In accordance with 40 CFR 60.4345, if the option to use a $NO_x$ CEMS is chosen:*

- *Each $NO_x$ diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to 40 CFR 60, except the 7-day calibration drift is based on unit operating days, not calendar days. With DEQ approval, Procedure 1 in Appendix F to 40 CFR 60 is not required. Alternatively, a $NO_x$ diluent CEMS that is installed and certified according to Appendix A to 40 CFR 75 is acceptable for use under 40 CFR 60, Subpart KKKK. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.*
- *As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, both the $NO_x$ monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the $NO_x$ emission rate for the hour.*
- *Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions.*
- *Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.*
- *The permittee shall maintain a quality assurance (QA) plan on-site for all of the continuous monitoring equipment described in 40 CFR 60.4345. For the CEMS and fuel flow meters, the permittee may, with DEQ approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to 40 CFR 75.*

Because the quality assurance (QA) plan was developed, requirements to develop these documents were considered satisfied and were removed.[7] Ongoing maintenance of, and compliance with, these documents is required.

Permit Conditions 4.25, 4.34, and 4.37 (Revised Permit Conditions 56, 66, and 70)

56. *NSPS 40 CFR 60, Subpart KKKK – $NO_x$ CEMS Monitoring Excess Emissions*

*The permittee shall comply with the requirements of 40 CFR 60.4350 for purposes of identifying excess emissions, in accordance with 40 CFR 60.4350:*

- *All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h) (Permit Condition 28).*
- *For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b) (Permit Condition 55), is obtained for both $NO_x$ and diluent monitors, the data acquisition handling system (DAHS) must calculate and record the hourly $NO_x$ emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A to 40 CFR 60. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$ (or the hourly average $CO_2$ concentration is less than 1.0 percent $CO_2$), a diluent cap value of 19.0 percent $O_2$ or 1.0 percent $CO_2$ (as applicable) may be used in the emission calculations.*
- *Correction of measured $NO_x$ concentrations to 15 percent $O_2$ is not allowed.*
- *If you have installed and certified a $NO_x$ diluent CEMS to meet the requirements of 40 CFR 75, DEQ can approve that only quality-assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in Subpart D of 40 CFR 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c) (Permit Condition 28).*
- *All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.*

- *Calculate the hourly average $NO_x$ emission rates, in units of the emission standards under 40 CFR 60.4320 (Permit Condition 37), using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:*
  - *For simple cycle operation:*

$$E = \frac{(NO_x)_h * (HI)_h}{P}$$

*Where:*

*$E$ = hourly $NO_x$ emission rate, in lb/MWh,*

*$(NO_x)_h$ = hourly $NO_x$ emission rate, in lb/MMBtu,*

*$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), and*

*$P$ = gross energy output of the CT in MW.*

  - *For combined-cycle complying with the output-based standard, use the simple-cycle operation equation above, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the CT, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:*

$$P = (Pe)_t + (Pe)_c + P_s + P_o$$

*Where:*

*$P$ = gross energy output of the stationary CT system in MW.*

*$(Pe)_t$ = electrical or mechanical energy output of the CT in MW,*

*$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and*

$$P_S = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}}$$

*Where:*

*$P_S$ = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,*

*$Q$ = measured steam flow rate in lb/h,*

*$H$ = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10^6$ = conversion from Btu/h to MW.*

*$P_O$ = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the CT.*

- *Use the calculated hourly average emission rates from this permit condition to assess excess emissions on a 30 unit operating day rolling average basis, as described in 40 CFR 60.4380(b)(1) (Permit Condition 70).*

*66. <u>Performance Test Monitoring</u>*

- *The permittee shall monitor and record the following operating conditions for the CT and duct burner during each performance test, unless otherwise approved by DEQ:*
  - *The $NO_x$ and CO CEMS continuous emissions data;*
  - *The CT and duct burner fuel flow rates in scf/hr, at least once every 20 minutes;*
  - *The SCR ammonia injection rate in gpm, at least once every 20 minutes;*
  - *The HRSG steam flow rates in lb/hr, at least once every 20 minutes;*
  - *The HRSG Stack exhaust gas flow rate in acfm, at least once each test;*

- *The HRSG Stack exhaust gas temperature in °F, at least once each test;*
- *The ambient temperature and relative humidity, at least once each test;*
- *The average actual load as a percentage of the base load of the CT for each test; and*
- *The gross energy output of the CT and the duct burner for each test.*

- *The permittee shall furnish DEQ a written report of the results of each performance test, in accordance with IDAPA 58.01.01.157 and the performance testing general provisions (Permit Condition 102).*

*70. <u>NSPS 40 CFR 60, Subpart KKKK - Excess Emissions for $NO_x$</u>*

*For the purpose of reports required under 40 CFR 60.7(c) (Permit Condition 28), periods of excess emissions and monitor downtime that must be reported are defined in 40 CFR 60.4380, in accordance with 40 CFR 60.4380.*

- *For turbines using CEMS, as described in 40 CFR 60.4335(b) and 40 CFR 60.4345 (Permit Condition 55):*
  - *An excess emissions is any unit operating period in which the 30-day rolling average $NO_x$ emission rate exceeds the applicable emission limit in 40 CFR 60.4320 (Permit Condition 37). A 30-day rolling average $NO_x$ emission rate is the arithmetic average of all hourly $NO_x$ emission data in ppm or ng/J (lb/MWh) measured by the CEMS for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly $NO_x$ emission rates for the preceding 30 unit operating days if a valid $NO_x$ emission rate is obtained for at least 75 percent of all operating hours.*
  - *A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: $NO_x$ concentration, $CO_2$ or $O_2$ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.*
  - *For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.*

The permittee has elected to comply with the concentration-based (ppm) rather than the output-based (lb/MWh) standards (Permit Condition 4.6).[8] As a result, monitoring of steam flow rate, steam temperature, and steam pressure was not required.

In addition, because monitoring of stack exhaust gas parameters (flow rate and temperature) was required only to verify the accuracy of stack parameters used in ambient air quality compliance modeling demonstrations, ongoing monitoring of these parameters during subsequent performance tests was not required.

Because quality-assured data is now required for compliance with Acid Rain program requirements, DEQ has required this data also to be used to demonstrate compliance with the $NO_x$ emission limit, in accordance with 40 CFR 60.4350(d).

<u>Permit Condition 4.26 (Revised Permit Condition 57)</u>

*57. <u>CO CEMS Monitoring for BACT and Annual Limits</u>*

*For the purposes of demonstrating compliance with the CO BACT emission limit (Permit Condition 33), the CO BACT secondary emission limits (Permit Conditions 34 and 35), and the CO annual emission limit (Permit Condition 36), the permittee shall comply with the following requirements:*

- *Each CO CEMS shall meet the requirements for CEMS set forth in 40 CFR 60, Subpart A (Permit Condition 28).*

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8 Reply and comments concerning the draft permit (Permit Condition 4.25), Idaho Power Company, received May 30, 2013 (2013AAG847).

- *Startup, shutdown, and low-load events shall be monitored in accordance with the startup, shutdown, and low-load events monitoring requirement (Permit Condition 51).*
- *All CO CEMS data shall be reduced to hourly averages according to the procedures set forth in 40 CFR 60.13(h) (Permit Condition 28).*
- *For each unit operating hour in which a valid hourly average is obtained for both the CO and $O_2$ diluent monitors, the data acquisition and handling system (DAHS) must calculate and record the hourly CO emission rate in units of ppm and lb/MMBtu, using the appropriate equation from Method 19 in Appendix A to 40 CFR 60 or as approved by DEQ. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$, a diluent cap value of 19.0 percent $O_2$ may be used in the emission calculations.*
- *All required fuel flow rate data must be reduced to hourly averages.*
- *Hourly, monthly, and annual averages shall be calculated using CEMS totals and excess emissions shall be assessed according to the procedures in the CO CEMS monitoring excess emissions for BACT and annual limits requirement (Permit Condition 58). Electronic archives are an acceptable form of documentation for recordkeeping.*
- *Monitor downtime shall be defined as set forth in 40 CFR 60.4380(b)(2) (Permit Condition 70), and shall include any unit operating hour in which the data for CO concentration is either missing or invalid.*
- *Excess emissions and monitor downtime shall be reported according to the procedures set forth in 40 CFR 60, Subpart A (Permit Condition 28) and in accordance with the excess emissions procedures and requirements (Permit Conditions 19 through 26).*
- *A test protocol shall be submitted to DEQ for each certification and recertification of the CEMS. Each test protocol shall be submitted to DEQ for approval at least 30 days prior to the test date. Following the approval of the initial test protocol, the permittee may waive this reporting requirement by providing a certified statement that each recertification test will be performed in the same manner as a test protocol previously approved for the CEMS.*
- *Within 180 days of permit issuance, the permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval, addressing the methods used to quantify emission concentrations and emission rates from the HRSG stack and the methods used to ensure data quality. The protocol must be sufficiently detailed to allow DEQ to verify emissions rate estimates for purposes of determining compliance. The permittee shall maintain the DEQ-approved protocols onsite at all times the CT is operated.*
- *Records of all CEMS emission data, calibration reports, excess emissions and monitor downtime reports, and maintenance performed shall be maintained in accordance with the monitoring and recordkeeping general provision (Permit Condition 103).*

Because the CEMS methodology and quality assurance and quality control (QA/QC) protocols were developed, requirements to develop these documents were considered satisfied and were removed.[7] Ongoing maintenance of, and compliance with, these documents is required.

<u>Permit Condition 4.33 (Revised Permit Conditions 64 and 65)</u>

*64. <u>Initial Performance Tests</u>*

- *Within 60 days of achieving the maximum production rate of the facility, but not later than 180 days after initial startup, performance testing shall be conducted on the HRSG Stack to demonstrate compliance with the following emission limits, in accordance with IDAPA 58.01.01.211 and IDAPA 58.01.01.157:*
  - *The $NO_x$ BACT emission limit in ppm (Permit Condition 33);*
  - *The CO BACT emission limit in ppm (Permit Condition 33);*
  - *The VOC BACT emission limit in ppm (Permit Condition 33);*
  - *The $PM_{10}$ emission limit in lb/hr (Permit Condition 39);*
  - *The ammonia emission limit in ppm (Permit Condition 40); and*
  - *The visible emission limit in percent opacity (Permit Condition 9).*

- *Each performance test shall be conducted in accordance with the test methods requirement (Permit Condition 27) and under the following operating conditions, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.211:*
  - *Emissions shall be measured after the duct burner rather than directly after the CT. The duct burner must be in operation during the performance test.*
  - *The permittee shall conduct three separate test runs for each performance test. The minimum time per run shall be 20 minutes.*
  - *Parameters shall be monitored and recorded as specified in the performance test monitoring requirement (Permit Condition 66).*

*65. <u>Initial Performance Tests – Low-Load Events</u>*

- *Within 60 days of achieving the maximum production rate of the facility, but not later than 180 days after initial startup, performance testing shall be conducted on the HRSG Stack to demonstrate compliance with the following emission limit, in accordance with IDAPA 58.01.01.211 and IDAPA 58.01.01.157:*
  - *The VOC BACT secondary emission limit for low-load events in lb/hr (Permit Condition 34).*
- *Each performance test shall be conducted in accordance with the test methods requirement (Permit Condition 27) and under the following operating conditions, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.211:*
  - *Each performance test shall be conducted with the CT operating at below 60% of base load.*
  - *The permittee shall conduct three separate test runs for each performance test. The minimum time per run shall be 20 minutes.*
  - *Parameters shall be monitored and recorded as specified in the performance test monitoring requirement (Permit Condition 66).*

Emissions units with an existing emission limitation <u>and</u> with PTE exceeding 49.9 T/yr are generally required to re-test every 5 years.[9] Consistent with this policy, ongoing testing to demonstrate compliance with VOC BACT and $PM_{10}$ emission limits was required. With consideration given to the requirement for continuous monitoring of $NO_x$ and CO emissions, additional testing to demonstrate compliance with NSPS and BACT emission limits for these pollutants was not required. Because ammonia and opacity emissions are not inherently limited based on fuel or other operational parameters, ongoing testing to demonstrate compliance with these limits was required. This permit condition was updated in accordance with Title V program guidance for "gap filling".[10]

<u>Permit Condition 4.35 (Revised Permit Condition 67)</u>

*67. <u>NSPS 40 CFR 60, Subpart KKKK – $SO_2$ Performance Tests</u>*

*The permittee shall conduct an initial performance test, as required in 40 CFR 60.8 (Permit Condition 28), in accordance with 40 CFR 60.4415(a) and using the methodologies provided in 40 CFR 60.4415(a). Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).*

Because the initial $SO_2$ performance testing was completed,[11] initial testing requirements were considered satisfied and were removed. Ongoing compliance with annual testing is required.

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[9] "Guidance for Requiring Source Tests in Air Permits," Doc ID AQ-IG-P001, rev. 1, Idaho DEQ, April 16, 2007 (2008AAF49).

[10] Discussed in the "Emission Limits and MRRR Section" of the Statement of Basis for Tier I Operating Permit No. T1-2013.0017 PROJ 61165 (2013AAG296).

[11] Appendix E – Fuel Analysis Records to "Stack RATA Final Report," Idaho Power, July 25, 2013 (2013AAI2568).

Permit Condition 5.3 (Revised Permit Condition 75)

75. *NSPS 40 CFR 60, Subpart IIII – Emission Standards for the Emergency Generator Engine*

*The permittee shall comply with the emission standards for new nonroad compression ignition (CI) engines in 40 CFR 60.4202 for the emergency generator engine, for all pollutants, in accordance with 40 CFR 60.4205(b).*

- *The certification emission standards for new nonroad CI engines in Table 1 to 40 CFR 89.112:*

***SUMMARY OF TABLE 1 TO 40 CFR 89.112 – EMISSION STANDARDS***

| *Rated Power (kW)* | *Tier* | *NMHC + $NO_x$ g/kW-hr* | *CO g/kW-hr* | *PM g/kW-hr* |
|---|---|---|---|---|
| *kW > 560* | *Tier 2* | *6.4* | *3.5* | *0.20* |

- *The certification emission standards for new nonroad CI engines in 40 CFR 89.113:*
  - *The exhaust opacity from nonroad CI engines shall not exceed 20 percent during the acceleration mode; 15 percent during the lugging mode; and 50 percent during the peaks in either the acceleration or lugging modes.*

The permittee requested removal of the opacity limits incorporated from NSPS Subpart IIII.[12] The emergency generator will be operated as a constant-speed engine qualifying for exemption under 40 CFR 89.113(c);

*40 CFR 89.113 ...............................Smoke emission standard.*

*(a) Exhaust opacity from compression-ignition nonroad engines for which this subpart is applicable must not exceed:*

*(1) 20 percent during the acceleration mode;*

*(2) 15 percent during the lugging mode; and*

*(3) 50 percent during the peaks in either the acceleration or lugging modes.*

*(b) Opacity levels are to be measured and calculated as set forth in 40 CFR part 86, subpart I. Notwithstanding the provisions of 40 CFR part 86, subpart I, two-cylinder nonroad engines may be tested using an exhaust muffler that is representative of exhaust mufflers used with the engines in use.*

*(c) The following engines are exempt from the requirements of this section:*

*(1) Single-cylinder engines;*

*(2) Propulsion marine diesel engines; and*

*(3) Constant-speed engines.*

Permit Condition 5.5 (Revised Permit Condition 77)

77. *Hours of Operation for Maintenance and Testing*

- *Operation of the emergency generator engine for maintenance and testing shall not exceed 4 hours of per calendar day and shall not exceed 60 hours in any consecutive 12 calendar month period.*
- *Operation of the fire pump engine for maintenance and testing shall not exceed 1 hour per calendar day and shall not exceed 30 hours in any consecutive 12 calendar month period.*

The permittee requested a revision of this limit to increase the annual hours of operation for the fire pump engine to meet maintenance and testing obligations.[13]

[12] Section 4.2.3 of "Tier I Permit Application Supplemental Information," Idaho Power Company, received April 30, 2013 (2013AAG702).

[13] Section 4.2.4 of "Tier I Permit Application Supplemental Information," Idaho Power Company, received April 30, 2013 (2013AAG702).

Permit Condition 5.6 (Revised Permit Condition 78)

78. *NSPS 40 CFR 60, Subpart IIII – Compliance Requirements*

- *The emergency generator engine and the fire pump engine may be operated for the purpose of maintenance checks and readiness testing in accordance with 40 CFR 60.4211(e), provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine.*
  - *Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary internal combustion engines (ICE) in emergency situations.*
  - *For approval of additional hours to be used for maintenance checks and readiness testing, a petition is not required if the permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of the emergency ICE beyond 100 hours per year.*
  - *Any operation other than emergency operation, and maintenance and testing is prohibited.*
- *The permittee shall operate and maintain the emergency generator engine and the fire pump engine and control devices according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, in accordance with 40 CFR 60.4211(a). In addition, the permittee may only change those settings that are permitted by the manufacturer. The permittee shall also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as applicable.*
- *The permittee shall comply by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) or (c) (Permit Condition 75 or 76), as applicable, for the same model year and maximum (or in the case of fire pump engines, National Fire Protection Association nameplate) engine power, in accordance with 40 CFR 60.4211(c). The engine shall be installed and configured according to the manufacturer's specifications.*

For purposes of clarification and to avoid confusion in complying with multiple hours of operation limits, the more stringent limitation in Permit Condition 5.5 was referenced in lieu of the 100 hours per year allowed under NSPS Subpart IIII (40 CFR 60.4211(f)(2). This requirement has not been streamlined, as the NSPS limit was separately cited. Because the compliance option allowing additional maintenance and testing beyond 100 hours per year is not required, the relevant recordkeeping requirement was also removed.[4]

Permit Condition 5.9 (Revised Permit Condition 81)

81. *NSPS 40 CFR 60, Subpart IIII – Monitoring Requirements*

*The permittee shall meet the monitoring requirements of 40 CFR 60.4209. In addition, the permittee shall also meet the monitoring requirements specified in 40 CFR 60.4211.*

- *The permittee shall install a non-resettable hour meter on the emergency generator engine and on the fire pump engine, prior to startup of each engine.*
- *If the emergency generator engine or the fire pump engine is equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the permittee when the high backpressure limit of the engine is approached.*

Because a particulate filter is not required for the emergency generator or fire pump engine to comply with the applicable emission standards under NSPS Subpart IIII,[4] the relevant backpressure monitoring requirement has been removed. A high-level citation referencing these requirements was retained.

Permit Condition 5.10 (Revised Permit Condition 82)

82. *NSPS 40 CFR 60, Subpart IIII – Fuel Requirements*

*The permittee shall use diesel fuel that meets the requirements of 40 CFR 80.510(a), in accordance with 40 CFR 60.4207(a). Beginning October 1, 2010, the permittee shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, in accordance with 40 CFR 60.4207(b).*

- *All nonroad diesel fuel is subject to the following per-gallon standards:*

- *15 parts per million by weight (ppmw) maximum sulfur content; and a*
- *Minimum cetane index of 40, or maximum aromatic content of 35 volume percent.*

This permit condition was revised to reflect the most stringent diesel fuel requirements, which became applicable June 1, 2010. These requirements have not been streamlined, as the complete subsection from Subpart IIII was cited (including all applicable limits).

Permit Condition 6.4 (Revised Permit Condition 90)

*90. Solids Content and Flow Rate*

- *The total dissolved solids content of the cooling tower water shall not exceed 5,000 milligrams per liter (mg/L).*
- *The circulating flow rate of the cooling tower water shall not exceed 63,200 gallons per minute.*

The permittee requested a revision of this limit to increase the cooling tower flow rate to reflect the installed equipment nameplate capacity.[14]

## 6. PUBLIC REVIEW

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this period, no comments were submitted in response to DEQ's proposed action. Refer to the Application Chronology section for a listing of relevant dates.

[14] Section 4.2.5 of "Tier I Permit Application Supplemental Information," Idaho Power Company, received April 30, 2013 (2013AAG702).

# APPENDIX A – EMISSION INVENTORIES

**Table 5: Existing Criteria Pollutants Emission Rates**

| Emissions Units | | NOx | | CO | | VOC | | $PM_{10}$[b] | | $PM_{2.5}$[m] | | $SO_2$ | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] |
| CT and Duct Burner[d] | peak-load[e] | 20.10 | 88.00 | 12.24 | 278.10 | 7.01 | 74.90 | 12.55 | 49.46 | 12.55 | 49.46 | 3.41 | 13.44 | 0.02 | 0.05 |
| | low-load[f] | 452.78 | | 70.35 | | 18.91 | | | | | | | | | |
| | startup/shutdown[g] | 304.56 | | 2510.0 | | 186.60 | | | | | | | | | |
| emergency generator engine[h] | | 11.60 | 0.35 | 6.30 | 0.19 | 0.73 | 0.02 | 0.36 | 0.01 | 0.36 | 0.01 | 0.01 | 0.00 | | |
| fire pump engine[i] | | 2.10 | 0.03 | 1.80 | 0.03 | 0.10 | 0.00 | 0.10 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | | |
| cooling tower | | | | | | | | 0.67 | 2.91 | 0.67 | 2.91 | | | | |
| dry chemical storage silos | | | | | | | | 0.04 | 0.01 | 0.04 | 0.01 | | | | |
| paved roads[l] | | | | | | | | 0.2 | 0.01 | 0.2 | 0.01 | | | | |
| unpaved roads[l] | | | | | | | | 0.27 | 0.01 | 0.27 | 0.01 | | | | |
| Facility-Wide Totals | | 466.48 | 88.38 | 2518.10 | 278.32 | 187.43 | 74.92 | 14.19 | 52.41 | 14.19 | 52.41 | 3.42 | 13.47 | 0.02 | 0.05 |

Existing Potential to Emit, Criteria Pollutants[a]

a). Short-term (lb/hr) and annual (T/yr) emission estimates assume the use of BACT and are based on daily and annual limits on hours of operation.

b). Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c). Tons per any consecutive 12 calendar month period, calculated as a 12 month rolling total.

d). Annual totals assume a maximum of 7,884 hr/yr operation, continuous duct-firing at steady-state, and include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation)

e). At steady-state and ≥ 60% of full-load operating conditions.

f). At steady-state and < 60% of full-load operating conditions.

g). At startup of shutdown operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).

h). Limited to 4 hr/day and 60 hr/yr operation for maintenance.

i). Limited to 1 hr/day and 30 hr/yr operation for maintenance and testing purposes.

j). Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 ppm and a circulating flow rate of 63,200 gpm.
k). Total emissions from the six (6) dry chemical storage silos. Annual totals assume each silo is loaded for up to 2 hours, 24 hr/yr.
l). Fugitive emission sources.
m). Particulate matter with an aerodynamic diameter less than or equal to a nominal two and a half (2.5) micrometers. $PM_{2.5}$ was not included in the initial PTC application in 2009 because $PM_{2.5}$ was not a regulated pollutant at that time. Although $PM_{2.5}$ emissions were not included in the initial PTC, it was stated in the PTC application that an assumption was made that $PM_{2.5}$ emissions were equal to $PM_{10}$ emissions. In order to adequately address the increase in $PM_{2.5}$ emissions due to the proposed changes, the $PM_{2.5}$ emissions associated with the existing PTC must be established. Therefore, $PM_{2.5}$ emissions were assumed to equal $PM_{10}$ emissions.

**Table 6: Proposed Criteria Pollutant Emission Rates**

| Emissions Units | | Proposed Potential to Emit, Criteria Pollutants[a] | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $NO_X$ | | CO | | VOC | | $PM_{10}$[b] | | $PM_{2.5}$[c] | | $SO_2$ | | Pb | |
| | | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] | lb/hr | T/yr[c] |
| CT and Duct Burner[d] | peak-load[e] | 20.10 | 88.00 | 12.24 | 278.10 | 7.01 | 74.90 | 12.55 | 49.46 | 12.55 | 49.46 | 3.41 | 13.44 | 0.02 | 0.05 |
| | low-load[f] | 452.78 | | 70.35 | | 18.91 | | | | | | | | | |
| | startup/shutdown[g] | 304.56 | | 2510.0 | | 186.60 | | | | | | | | | |
| emergency generator engine[h,i] | | 12.80 | 0.39 | 7.00 | 0.21 | 0.80 | 0.02 | 0.40 | 0.01 | 0.40 | 0.01 | 0.01 | 0.00 | | |
| fire pump engine[j] | | 2.00 | 0.03 | 1.70 | 0.03 | 0.10 | 0.00 | 0.10 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | | |
| cooling tower[k] | | | | | | | | 0.81 | 3.50 | 0.81 | 3.50 | | | | |
| dry chemical storage silos[l] | | | | | | | | 0.13 | 0.01 | 0.13 | 0.01 | | | | |
| above ground storage tank[m] | | | | | | 0.03 | 0.15 | | | | | | | | |
| paved roads[n] | | | | | | | | 0.2 | 0.01 | 0.2 | 0.01 | | | | |
| unpaved roads[n] | | | | | | | | 0.27 | 0.01 | 0.27 | 0.01 | | | | |
| **Facility-Wide Totals** | | **467.58** | **88.42** | **2518.70** | **278.35** | **187.53** | **75.07** | **14.46** | **53.00** | **14.46** | **53.00** | **3.42** | **13.47** | **0.02** | **0.05** |

a). Short-term (lb/hr) and annual (T/yr) emission estimates assume the use of BACT and are based on daily and annual limits on hours of operation.

b). Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c). Tons per any consecutive 12 calendar month period, calculated as a 12 month rolling total.

d). Annual totals assume a maximum fuel use of17,884,2687 MMBtu/yr, continuous duct-firing at steady-state, and include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation)

e). At steady-state and ≥ 60% of full-load operating conditions.

f). At steady-state and < 60% of full-load operating conditions.

g). At startup or shutdown operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).

h). Limited to 4 hr/day and 60 hr/yr operation for maintenance.

i). Assumes linear increase in emission rates from PTC emission rate based on incremental unit horsepower increase (1,214 hp / 1,102 hp).

j). Annual emissions proposed to increase to allow 40 hr/yr instead of 30 hr/yr as included in PTC application. Also, assumes a linear decrease in emission rate based on unit horsepower decrease from 315 hp to 305 hp.

k). Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 ppm and a circulating flow rate of 76,151 gpm.

l). Total emissions from the three (3) dry chemical storage silos. Annual totals assume each silo is loaded for up to 2 hours, and 48 hr/yr.

m). Emission rates were determined using the EPA's TANKS program. Assumes both the gasoline and diesel tank are refilled with 250 gallons of fuel (tank capacity) every day with an annual throughput of 91,250 gallons of gasoline and 91,250 gallons of diesel.

n). Fugitive emission sources.

o). Particulate matter with an aerodynamic diameter less than or equal to a nominal two and a half (2.5) micrometers. $PM_{2.5}$ emissions are assumed to equal $PM_{10}$ emissions.

**Table 7: Proposed Change in Emission Rates**

**Proposed Changes in Potential to Emit, Criteria Pollutants[a]**

| Emissions Units | | $NO_X$ | | CO | | VOC | | $PM_{10}$[b] | | $PM_{2.5}$[c] | | $SO_2$ | | Pb | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr | lb/hr | T/yr |
| CT and Duct Burner | peak-load | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | low-load | 0.00 | | 0.00 | | 0.00 | | | | | | | | | |
| | startup/shutdown | 0.00 | | 0.00 | | 0.00 | | | | | | | | | |
| emergency generator engine | | 1.20 | 0.04 | 0.70 | 0.02 | 0.07 | 0.00 | 0.04 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | | |
| fire pump engine | | (0.10) | 0.00 | (0.10) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | |
| cooling towers | | | | | | | | 0.14 | 0.59 | 0.14 | 0.59 | | | | |
| dry chemical storage silos | | | | | | | | 0.09 | 0.00 | 0.09 | 0.00 | | | | |
| above ground storage tank | | | | | | 0.03 | 0.15 | | | | | | | | |
| paved roads | | | | | | | | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| unpaved roads | | | | | | | | 0.00 | 0.00 | 0.00 | 0.00 | | | | |
| **Facility-Wide Totals** | | **1.10** | **0.04** | **0.60** | **0.02** | **0.10** | **0.15** | **0.27** | **0.59** | **0.27** | **0.59** | **0.00** | **0.00** | **0.00** | **0.00** |

a). All emission rate changes contained in this table were determined by subtracting the emission rates proposed in Table ~~7~~ 6, with the emission rates in Table ~~6~~ 5 of this analysis.

b). Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.

c). Particulate matter with an aerodynamic diameter less than or equal to a nominal two and a half (2.5) micrometers.

## 5.4. HAPS/TAPS – Proposed Change in Emission Rates

Table 8 below provides a comparison of the increase in Toxic Air Pollutants (TAP) for the combined action of all of the requested changes included in this request.

**Table 8: Proposed Change in HAP/TAP Emissions**

| Toxic Air Pollutants[a] | | | |
|---|---|---|---|
| Pollutant | Category | Annual Average [lb/hr] | 24-Hour Average [lb/hr] |
| 1,3-Butadiene | HAP / TAP-586 | 1.96E-08 | 3.57E-07 |
| Acenaphthene | HAP / TAP-586 | 1.08E-08 | 2.59E-07 |
| Acenaphthylene | HAP / TAP-586 | 2.25E-08 | 5.31E-07 |
| Acetaldehyde | HAP / TAP-586 | 4.38E-07 | 8.33E-06 |
| Acrolein | HAP / TAP-585 | 6.33E-08 | 1.26E-06 |
| Anthracene | HAP / TAP-586 | 3.59E-09 | 8.17E-08 |
| Benzene | HAP / TAP-586 | 4.36E-04 | 4.83E-04 |
| Benzo(a)pyrene | HAP / TAP-586 | 6.49E-10 | 1.52E-08 |
| Benzo(g,h,l)perylene | HAP / TAP-586 | 1.45E-09 | 3.37E-08 |
| Cyclohexane | HAP / TAP-585 | 4.57E-05 | 4.57E-05 |
| Ethyl alcohol | HAP / TAP-585 | 5.48E-04 | 5.48E-04 |
| Fluoranthene | HAP / TAP-586 | 3.81E-09 | 6.95E-08 |
| Fluorene | HAP / TAP-586 | 4.22E-08 | 9.39E-07 |
| Formaldehyde | HAP / TAP-586 | 7.61E-07 | 1.49E-05 |
| Naphthalene | TAP-585 | 3.23E-07 | 7.60E-06 |
| Phenanthrene | HAP / TAP-586 | 1.03E-07 | 2.41E-06 |
| Propylene oxide | HAP / TAP-585 | 7.31E-06 | 1.70E-04 |
| Pyrene | HAP / TAP-586 | 1.04E-08 | 2.39E-07 |
| Toluene | HAP / TAP-585 | 2.41E-04 | 2.58E-04 |
| 1,2,4-Trimethylbenzene | HAP / TAP-585 | 1.03E-05 | 1.03E-05 |
| Vanadium | TAP-585 | 5.42E-07 | 1.27E-05 |
| Xylenes | HAP / TAP-585 | 4.17E-05 | 5.38E-05 |

a). Combined change in HAP/TAPS for: Emergency Diesel Generator, Emergency Diesel Fire Pump, and AST.

# APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSIS

***MEMORANDUM***

| | |
|---|---|
| **DATE:** | August 14, 2013 |
| **TO:** | Morrie Lewis, Permit Writer, Air Program |
| **FROM:** | Kevin Schilling, Stationary Source Modeling Coordinator, Air Program |
| **PROJECT:** | P-2009.0092 PROJ 61199 PTC Application for revisions to the Idaho Power Company – Langley Gulch Power Plant, Permit to Construct |
| **SUBJECT:** | Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAP) |

## 1.0 Summary

Idaho Power Company (IPC) submitted a Permit to Construct (PTC) application for revisions to their current permit for construction and operation of the Langley Gulch Power Plant (LGPP), located near New Plymouth, Idaho. Analyses of projected pollutant impacts to ambient air resulting from the proposed revision were submitted to DEQ, demonstrating that the proposed modification would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02 and 203.03 [Idaho Air Rules Section 203.02 and 203.03]).

The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the pollutant dispersion modeling analyses used to demonstrate that the estimated emissions associated with operation of the proposed facility or modification will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. Evaluation of emissions estimates was performed by the permit writer and was addressed in the main body of the Statement of Basis.

The submitted modeling information and air quality impact analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was not within the scope of this DEQ modeling review); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the modification as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from emissions associated with the modification as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable National Ambient Air Quality Standards (NAAQS) at ambient air locations where and when the modification has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emission increases associated with the modification do not result in increased ambient air impacts exceeding allowable TAP increments. Table 1 presents key assumptions and results to be considered in the development of the permit.

| Table 1. KEY CONDITIONS USED IN MODELING ANALYSES | |
|---|---|
| **Criteria/Assumption/Result** | **Explanation/Consideration** |
| The stack height of engines powering the emergency generator and the fire water pump must be at least 20 feet in height. | Stack height is critical in determining modeled impacts for a source. |
| Flow rates to the cooling towers will not exceed the value used to estimate revised emission rates described in this memorandum. | Flow rates directly affect emissions, and NAAQS compliance is not assured for emission rates greater than those listed in this memorandum. |
| Public access to all areas inside the outer fence is legally and effectively precluded. | The methods used to demonstrate NAAQS compliance require that the fenced property boundary be used as the ambient air boundary. |

The proposed revision involves the following: 1) increase the cooling tower flow rate limit; and 2) revise equipment nameplate information and resulting emission estimates for the dry chemical storage silos and emergency generator and fire pump engines.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department that operation of the proposed facility or modification will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 and other portions of this memorandum are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

## 2.0 Background Information

### 2.1 Applicable Air Quality Impact Limits and Modeling Requirements

This section identifies applicable ambient air quality standards and analyses used to demonstrate compliance with air quality standards.

#### 2.1.1 Area Classification

The facility is located near New Plymouth, Idaho, in Payette County. The area is designated as attainment or unclassifiable for all pollutants.

#### 2.1.2 Modeling Applicability for Criteria Pollutants

Idaho Air Rules Section 203.02 state that a PTC cannot be issued unless the application demonstrates to the satisfaction of DEQ that the new source or modification will not cause or significantly contribute to a NAAQS violation. Atmospheric dispersion modeling is used to evaluate the potential impact of a proposed project to ambient air and demonstrate NAAQS compliance. However, if the emissions associated with a project are very small, project-specific modeling analyses may not be necessary.

If the emissions increase associated with a project are below modeling applicability thresholds established in the *Idaho Air Quality Modeling Guideline* (http://www.deq.idaho.gov/media/355037-modeling-guideline.pdf; State of Idaho Guideline for Performing Air Quality Impact Analyses. Doc. ID AQ-011 {rev. 2, July 2011}), then a project-specific analysis is not required. Modeling applicability emissions thresholds were developed by DEQ based on modeling of a hypothetical source designed to reasonably assure that impacts are below applicable Significant Impact Levels (SIL). DEQ has established two threshold levels: Level 1 thresholds are unconditional thresholds, requiring no approval for use by DEQ; Level 2 thresholds are conditional upon DEQ approval, which depends on evaluation of the project and the site, including emissions quantities, stack parameters, number of sources emissions are distributed amongst, distance between the sources and the ambient air boundary, and the presence of sensitive receptors near the ambient air boundary.

Since the permit revision project effectively corrects the previously issued permit and analyses supporting that permit, rather than proposes a modification of an existing plant/process, the modeling thresholds are not appropriate for those NAAQS that were in effect at the time of permit issuance. NAAQS compliance is assured by correcting those previous analyses, or performing analyses that indicate the conclusions of those analyses would not change had the previous analyses been performed for the facility as it was built and proposing to operate. The changes can be assessed as a modification for those NAAQS that were not applicable at the time the original permit was issued.

1-hour $NO_2$ and 1-hour $SO_2$

The 1-hour $NO_2$ NAAQS and the 1-hour $SO_2$ NAAQS were not applicable for permitting analyses at the time the original permit was issued. Therefore, DEQ assessed the modeling requirements for the emissions increase associated with the proposed permit changes as a modification to an existing source. The only emissions increases for 1-hour $NO_2$ and $SO_2$ are from the emergency generator and fire water pump. Both of these sources are for emergency use, with periodic engine testing. DEQ analyses have shown that emissions from intermittent operation of emergency engines for testing purposes can only have a substantial contribution to a NAAQS violation at receptor locations where other continuous sources already have a significant impact. Therefore, DEQ has determined that intermittent emissions can typically be excluded from the 1-hour $NO_2$ and 1-hour $SO_2$ SIL analyses.

24-hour and annual $PM_{2.5}$

$PM_{2.5}$ NAAQS were applicable at the time the original permit was issued. At that time, EPA policy was for $PM_{2.5}$ compliance to be demonstrated using the $PM_{10}$ analyses as a surrogate. EPA now requires a specific $PM_{2.5}$ modeling analysis. $PM_{2.5}$ compliance was demonstrated for this permit revision by both revising the previous $PM_{10}$ modeling analyses that were used as a $PM_{2.5}$ surrogate and by assessing the change in $PM_{2.5}$ emissions as a modification.

The change in emissions for the engines and the cooling towers is relatively simple because the location and release parameters for these sources are very similar to how they were modeled in the analyses supporting the issuance of the existing permit. The dry chemical storage silos have changed substantially from the previous modeling analyses, including: 1) construction and operation of three storage silos rather than the six that were modeled in the previous analyses; 2) location of the storage silos were about 30 meters northwest of the originally modeled location, which is more to the interior of the facility rather than along the modeled ambient air boundary; 3) the release height from the silos increased from 36 feet for all silos in the previous analyses to 65.4 feet, 44.6 feet, and 41.3 feet. Since the release parameters are not similar, the entire emissions quantity from the silos is considered in the modeling applicability calculation, rather than just the increase, as directed by the *Idaho Air Quality Modeling Guideline.*

Attachment 1 provides details on the calculation of the emission increase for $PM_{2.5}$ modeling applicability purposes. The $PM_{2.5}$ emission increase exceeds DEQ Level 1 modeling thresholds but is well below

Level 2 modeling thresholds, as shown in Table 2. Level 2 Modeling thresholds are approvable on a case-by-case basis for sources with good dispersion characteristics compared to the hypothetical source modeled for development of the threshold. Although the release height, temperature, and/or flow velocity of the sources are not as conducive to good dispersion as what was used to establish the Level 2 thresholds, DEQ determined Level 2 thresholds are appropriate because of the following:

- The applicable sources for the project are numerous and separated from each other by considerable distance, effectively diluting the impact of a given total emissions quantity.
- The closest distance to the fenced property boundary is about 160 meters, and in most directions and for most other sources associated with the project, the distance to the fenced property boundary is considerably greater.
- There are no sensitive receptors in the immediate area (homes, schools, parks, hospitals, etc.).

**Table 2. EMISSIONS INCREASE AND MODELING THRESHOLDS**

| Averaging Period/Pollutant | 24-hour $PM_{2.5}$ | Annual $PM_{2.5}$ |
|---|---|---|
| **Applicable Emissions Increase** | 0.13 lb/hr | 0.01 T/yr |
| **Level 1 Modeling Threshold** | 0.054 lb/hr | 0.35 T/yr |
| **Level 2 Modeling Threshold** | 0.63 lb/hr | 4.1 T/yr |

### *2.1.3 Significant and Cumulative NAAQS Impact Analyses*

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or the emissions increase associated with a modification exceed the significant impact levels (SILs) of Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02. A cumulative NAAQS impact analysis may also be required for permit revisions driven by compliance/enforcement actions, any correction of emissions limits or other operational parameters that may affect pollutant impacts to ambient air, or other cases where DEQ believes NAAQS may be threatened by the emissions associated with the proposed project.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from facility-wide emissions and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 3. Table 3 also lists SIL and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis.

Compliance with Idaho Air Rules Section 203.02 is demonstrated if: a) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or b) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or c) if the cumulative NAAQS analysis showed NAAQS violations, the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

$NO_2$ and $SO_2$ short-term standards have recently been promulgated by EPA. The standards became applicable for permitting purposes in Idaho when they were incorporated by reference *sine die* into Idaho Air Rules (Spring 2011).

The $PM_{2.5}$ annual standard was changed from 15 $\mu g/m^3$ to 12 $\mu g/m^3$ on December 14, 2012. The revised standard will not become applicable for permitting purposes until it is incorporated *sine die* into Idaho Air Rules (Spring 2014).

| Table 3. APPLICABLE REGULATORY LIMITS | | | | |
|---|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Significant Impact Levels[a] ($\mu g/m^3$)[b]** | **Regulatory Limit[c] ($\mu g/m^3$)** | **Modeled Design Value Used[d]** |
| $PM_{10}$[e] | 24-hour | 5.0 | 150[f] | Maximum 6th highest[g] |
| $PM_{2.5}$[h] | 24-hour | 1.2[i] | 35[j] | Mean of maximum 1st highest[k] |
| | Annual | 0.3[i] | 15[l] | Mean of maximum 1st highest[k] |
| Carbon monoxide (CO) | 1-hour | 2,000 | 40,000[m] | Maximum 2nd highest[n] |
| | 8-hour | 500 | 10,000[m] | Maximum 2nd highest[n] |
| Sulfur Dioxide ($SO_2$) | 1-hour | 3 ppb[o] (7.8 $\mu g/m^3$) | 75 ppb[p] (196 $\mu g/m^3$) | Mean of maximum 4th highest[q] |
| | 3-hour | 25 | 1,300[m] | Maximum 2nd highest[n] |
| | 24-hour | 5 | 365[m] | Maximum 2nd highest[n] |
| | Annual | 1.0 | 80[r] | Maximum 1st highest[n] |
| Nitrogen Dioxide ($NO_2$) | 1-hour | 4 ppb[o] (7.5 $\mu g/m^3$) | 100 ppb[s] (188 $\mu g/m^3$) | Mean of maximum 8th highest[t] |
| | Annual | 1.0 | 100[r] | Maximum 1st highest[n] |
| Lead (Pb) | 3-month[u] | NA | 0.15[r] | Maximum 1st highest[n] |
| | Quarterly | NA | 1.5[r] | Maximum 1st highest[n] |

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms per cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. $PM_{2.5}$ SILs were vacated and remanded as of January, 2013.
j. 3-year average of the upper 98th percentile of the annual distribution of 24-hour concentrations.
k. 5-year mean of the 1st highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. The monitoring design value is used for background concentrations for $PM_{2.5}$ analyses. This approach is also used for the significant impact analysis.
l. 3-year average of annual concentration. The NAAQS was revised to 12 $\mu g/m^3$ on December 14, 2012. However, this standard will not be applicable for permitting purposes in Idaho until it is incorporated by reference *sine die* into Idaho Air Rules (Spring 2014).
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year average of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year average of maximum modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year average of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year average of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.

### 2.1.4 *Toxic Air Pollutant Analyses*

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permitting requirements for toxic air pollutants (TAP) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regard to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the total project-wide emission increases of any TAP associated with a new source or modification exceeds screening emission levels (EL) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AAC) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACC) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

### 2.2 *Background Concentrations*

Background concentrations are used in the cumulative NAAQS impact analyses to account for impacts from sources not explicitly modeled. Background concentrations were only needed for CO, since that was the only pollutant emitted from the facility that had impacts above the SIL for the originally performed modeling. The 1-hour CO background concentration of 3,600 $\mu g/m^3$ was used for the revised analysis. This value is a DEQ default background for rural/agricultural areas and was used for the analysis supporting the current permit.

## 3.0 Modeling Impact Assessment

### 3.1 *Modeling Methodology*

This section describes the modeling methods used by the applicant to demonstrate preconstruction compliance with applicable air quality standards.

### *3.1.1 Overview of Analyses*

The application was initially submitted without ambient impact analyses, under the assumption that proposed changes would be considered as below regulatory concern. DEQ determined that the proposed changes represented a revision to the existing permit and could not be processed under exemption rules. DEQ also determined the changes were most appropriately assessed as a revision/correction to the permit to reconcile consistency issues between the permit and the plant and how the plant needs to operate.

Table 4 provides a brief description of parameters used in the modeling analyses supporting the current permit.

**Table 4. MODELING PARAMETERS**

| Parameter | Description/Values | Documentation/Additional Description |
|---|---|---|
| General Facility Location | New Plymouth | The area is an attainment or unclassified area for all criteria pollutants. |
| Model | AERMOD | AERMOD with the PRIME downwash algorithm, version 09292, was used for all air impact analyses. |
| Meteorological Data | Site-specific surface<br>Boise upper air | 1 year of on-site data collected. See Section 3.1.6 of this memorandum. |
| Terrain | Considered | Receptor, building, and emissions source elevations were determined using Digital Elevation Model (DEM) files. |
| Building Downwash | Considered | Plume downwash was considered for the structures associated with the facility. |
| Receptor Grid | Grid 1 | 25-meter spacing along the ambient air boundary |
| | Grid 2 | 100-meter spacing out to at least 1,000 meters. |
| | Grid 3 | 500-meter spacing out to 10,000 meters. |
| | MaxGrid | 50-meter spacing centered on point of maximum impact. |

### *3.1.2 Modeling Methodology*

A modeling protocol was not submitted to DEQ prior to the application, as modeling analyses were not submitted with the application. Revised estimates of potential air quality impacts caused by the proposed revisions of the permit were calculated by assessing the change in emissions/operations in the context of results from the analyses submitted with the original permit application (2010). Previously performed project-specific modeling was generally conducted using data and methods described in the *Idaho Air Quality Modeling Guideline*.

Impacts of facility operations on ambient air quality are estimated by atmospheric dispersion models, using site/source parameters and data, along with maximum emissions levels for the applicable averaging period. Air quality impacts predicted by models are a direct, linear function of emissions quantities. Doubling emissions from a specific source will double the air quality impact at any specific receptor, provided other dispersion-affecting variables are unchanged.

IPC chose to demonstrate compliance with NAAQS and TAP through use of analyses supporting the previous permit, rather than rerun the modeling analyses with the revised emissions. The pollutant impacts for specific emissions sources were scaled by the ratio of the emissions, equal to the revised allowable emissions to existing allowable emissions. The ratio method must be implemented on a point-by-point basis for this project since it involves multiple emissions points. The total impact is calculated by conservatively adding the point-by-point revised impacts.

Sections 3.1.4 through 3.1.9 provide a description of the modeling methods and data used in analyses submitted with the application that supports the initially issued permit.

### *3.1.3 Evaluation of Ozone Impacts*

Ozone ($O_3$) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. $O_3$ is formed in the atmosphere through reactions of VOC, $NO_x$, and sunlight. Total emissions of VOC and $NO_x$ were not substantially changed from the initial permit application. Therefore, DEQ has concluded that revision of the permit will not cause or measurably contribute to a violation of the 8-hour $O_3$ NAAQS.

### *3.1.4 Model Selection*

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight-line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

The analyses supporting the existing permit were performed using AERMOD version 09292. The model was not rerun for this permit revision.

### *3.1.5 Meteorological Data*

An on-site meteorological tower was erected to collect the following data: wind speed, wind direction, standard deviation of wind direction, vertical wind speed, and temperature, all at 10 meters; temperature, pressure, solar radiation, and relative humidity all at 2 meters. The data were collected as per PSD monitoring guideline specifications. One year of data was collected, beginning December 3, 2008. Cloud cover observations used for determining mixing heights were obtained from the Ontario Municipal Airport, Oregon (WBAN 24162), about 18 miles northwest of the site. Upper air data were obtained from the Boise Air Terminal National Weather Service station (WBAN 24162).

Meteorological data were processed using AERMET version 06341. Month-specific surface characteristics were determined by using the program AERSURFACE (version 08009). Details on the meteorological data processing are presented in the application.

### *3.1.6 Terrain Effects*

Terrain effects on dispersion were considered in the analyses supporting the current permit. Receptor elevations and hill heights were obtained by using AERMAP (version 09040) and Digital Elevation Model (DEM) 7.5-minute files.

### *3.1.7 Building Downwash*

Potential downwash effects on the emissions plume were accounted for in the model by using building parameters as described in the application supporting the current permit. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and release parameters for input to AERMOD.

### *3.1.8 Ambient Air Boundary*

A security fence around the immediate area of the LGPP was used as the boundary to ambient air for the original analyses, as this represents a secure physical barrier. The property boundary is also fenced, but this was conservatively not used as the ambient air boundary.

IPC has now indicated that the property boundary fence can be used to legally and effectively preclude public access. DEQ's acceptance of the analyses used for these permit revision analyses assumes the property boundary fence is the ambient air boundary.

### *3.1.9 Receptor Network*

Table 4 describes the receptor network used in the modeling analyses supporting the current permit. DEQ contends that the receptor network was adequate to reasonably assure compliance with applicable air quality standards at all ambient air locations.

## *3.2 Emission Rates*

Emissions rates of criteria pollutants and TAP for the proposed revisions were provided by the applicant for various applicable averaging periods. DEQ review of the modeling analyses, as described in this memorandum, did not include review of emission rates for accuracy. Review and approval of estimated emissions was performed by the DEQ permit writer.

This permit revision does not affect emissions from the main turbine stack, so these emission rates were not listed in this memorandum.

### *3.2.1 Criteria Pollutant Emissions Rate*

Table 5 lists criteria pollutant emissions rates used in the project-specific modeling analyses for all applicable averaging periods. The rates listed represent the maximum allowable rate as averaged over the specified period.

Total changes in the 24-hour and annual $PM_{2.5}$ emissions were calculated at 0.27 pounds per hour and 0.61 ton per year, respectively. This level of emissions is above the Level 1 Modeling Thresholds but below the Level 2 Modeling Thresholds. DEQ determined Level 2 Modeling Thresholds are appropriate for the project and further air impact analyses were not required for 24-hour and annual $PM_{2.5}$, as described in Section 2.1.2 of this memorandum.

### *3.2.2 TAP Emissions Rates*

TAP emissions rates were not affected by the permit revision.

| Table 5. CRITERIA POLLUTANT EMISSIONS USED IN ANALYSES | | | | | |
|---|---|---|---|---|---|
| Emission Point | Pollutant | Averaging Period | Emission Rate (lb/hr)[a] | | |
| | | | Original Analysis | Revised Analysis | Change |
| Fire Pump (FP) | CO | 1-hour | 1.8 | 1.7 | -0.1 |
| | | 8-hour | 0.2252 | 0.425 | 0.200 |
| | $PM_{2.5}$[b] | 24-hour | 0.00430 | 0.00833 | 0.00403 |
| | | Annual | 0.000356 | 0.000457 | 0.000101 |
| | $PM_{10}$[c] | 24-hour | 0.00430 | 0.00833 | 0.00403 |
| | $NO_x$ | Annual | 0.00685 | 0.00685 | 0.0 |
| | $SO_2$ | 1-hour[d] | 0.00107 | 0.000938 | -0.00013 |
| Generator (EG) | CO | 1-hour | 6.30 | 7.00 | 0.70 |
| | | 8-hour | 3.152 | 3.50 | 3.48 |
| | $PM_{2.5}$ | 24-hour | 0.0606 | 0.0667 | 0.0061 |
| | | Annual | 0.00249 | 0.00274 | 0.00025 |
| | $PM_{10}$ | 24-hour | 0.0606 | 0.0667 | 0.0061 |
| | $NO_x$ | Annual | 0.0799 | 0.0879 | 0.0080 |
| | $SO_2$ | 1-hour | 0.0112 | 0.0147 | 0.0035 |
| Cooling Tower Cells 1-7[e] (CT1 – CT7) | $PM_{2.5}$ | 24-hour | 0.0949 | 0.1143 | 0.0194 |
| | | Annual | 0.0949 | 0.1143 | 0.0194 |
| | $PM_{10}$ | 24-hour | 0.0949 | 0.1143 | 0.0194 |
| Chemical Storage Silos 1-3 | $PM_{2.5}$ | 24-hour | 0.00714[f] | 0.01075[g] | 0.00361[h] |
| | | Annual | 0.000235[f] | 0.000707[g] | 0.000472[h] |
| | $PM_{10}$ | 24-hour | 0.00714[f] | 0.01075[g] | 0.00361[h] |

a. Pounds per hour emission rate used in the air impact analyses for specified averaging periods.
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
d. Also used for 3-hour, 24-hour, and annual. The 24-hour and annual standards remain in effect until one year after the area is designated for the 2010 standard.
e. Emissions from each of seven cooling tower cells.
f. Emissions from each of six storage silos.
g. Emissions from each of three storage silos.
h. Change in emissions per silo (note the total number of silos were reduced by the revision).

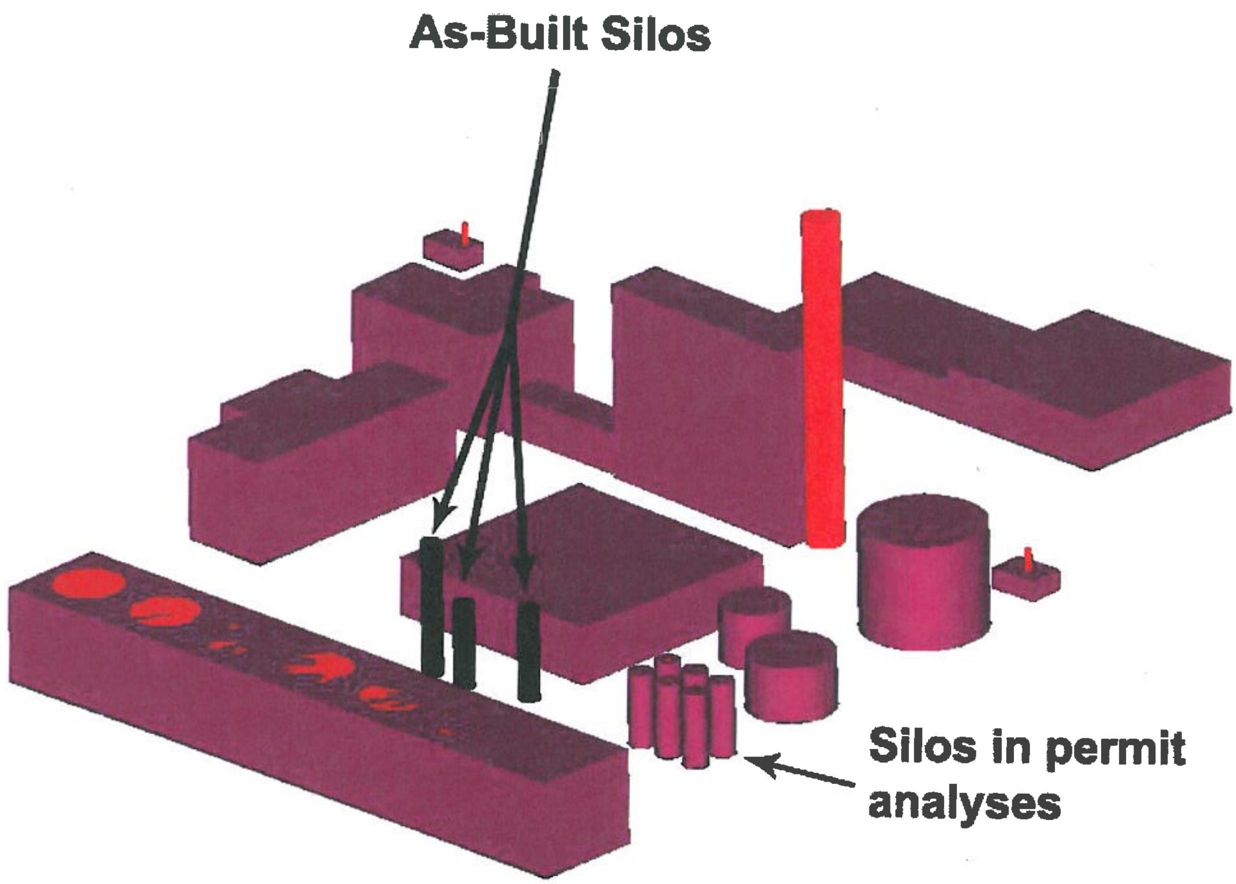
## 3.3 Emission Release Parameters

IPC did not indicate that emission release parameters had changed from the final analyses used for the existing permit issued in 2010. Release parameters for the internal combustion engines powering the emergency generator and the fire water pump are not expected to change substantially since the engines are approximately the same power rating as was previously used in the modeling analyses. However, it is important that the stack heights be maintained at not less than 20 feet to assure pollutant dispersion is as effective as what was used in the previous analyses.

Release parameters for the dry chemical storage silos changed substantially from what was originally modeled for the current permit. The following are changes from how the silos were originally modeled:

- Original modeling included six silos, and final design was only three silos.
- All six originally modeled silos had exhaust release points at 36 feet, while the final designed silos were 65.4 feet for the lime silo, 44.6 feet for the soda ash silo, and 41.3 feet for the magnesium oxide silo.
- Exhaust flow from the originally modeled silos were 1,000 actual cubic feet per minute while final design was 1,200 actual cubic feet per minute.
- The location of the chemical storage silos changed, with the final design location about 30 meters to the northwest of the originally modeled location. Figure 1 shows the change in the location, height, and number of storage silos.

**Figure 1 – Change Dry Chemical Storage Silo Modeling**




### *3.4 Results for Significant Impact Level Analyses*

Attachments 2-5 provide details on the SIL analyses.

#### *3.4.1 8-Hour CO Impacts*

Modeling analyses supporting the current permit showed that maximum facility-wide 8-hour CO impacts were 195 $\mu g/m^3$, well below the 500 $\mu g/m^3$ SIL.

Allowable emissions of 8-hour CO only changed for the engines powering the emergency generator and the fire water pump. NAAQS compliance was demonstrated by using the previously performed SIL analyses to show revised impacts are still below the SIL. Attachment 2 provides the details of the revisions to the analysis.

The total additive change in maximum 8-hour CO impacts is 62.1 $\mu g/m^3$. Adding this to the previously modeled facility-wide impact of 194.8 $\mu g/m^3$, gives a revised facility-wide impact of 256.7 $\mu g/m^3$. This is well below the 500 $\mu g/m^3$ SIL.

### *3.4.2 24-Hour $PM_{10}$ Impacts*

Modeling analyses supporting the originally issued permit showed that maximum facility-wide 24-hour $PM_{10}$ impacts were 1.87 $\mu g/m^3$, well below the 5.0 $\mu g/m^3$ SIL.

Allowable emissions of 24-hour $PM_{10}$ changed for the engines powering the emergency generator and the fire water pump, the cooling towers, and the dry chemical storage silos. NAAQS compliance was demonstrated by using the previously performed SIL analysis to show that conservatively revised impacts are still below the SIL. Attachment 3 provides the details of the revisions to the analysis.

The total additive change in maximum 24-hour $PM_{10}$ impacts was estimated by DEQ to be 1.314 $\mu g/m^3$. Adding this to the previously modeled facility-wide impact of 1.87 $\mu g/m^3$, gives a revised facility-wide impact of 3.18 $\mu g/m^3$. This is well below the 5.0 $\mu g/m^3$ SIL.

### *3.4.3 Annual $PM_{10}$ Impacts*

The annual $PM_{10}$ NAAQS is no longer applicable, having been replaced by the annual $PM_{2.5}$ NAAQS. Correcting the previous annual $PM_{10}$ analysis was necessary because annual $PM_{10}$ was modeled as a surrogate for annual $PM_{2.5}$.

Modeling analyses supporting the originally issued permit showed that maximum facility-wide annual $PM_{10}$ impacts were 0.233 $\mu g/m^3$, well below the 1.0 $\mu g/m^3$ SIL.

Allowable emissions of annual $PM_{10}$ changed for the engines powering the emergency generator and the fire water pump, the cooling towers, and the dry chemical storage silos. NAAQS compliance was demonstrated by using the previously performed SIL analysis to show that conservatively revised impacts are still below the SIL. Attachment 4 provides the details of the revisions to the analysis.

The total additive change in maximum annual $PM_{10}$ impacts was estimated by DEQ to be 0.065 $\mu g/m^3$. Adding this to the previously modeled facility-wide impact of 0.233 $\mu g/m^3$, gives a revised facility-wide impact of 0.30 $\mu g/m^3$. This is well below the 1.0 $\mu g/m^3$ SIL.

### *3.4.4 Annual $NO_2$ Impacts*

Modeling analyses supporting the originally issued permit showed that maximum facility-wide annual $NO_2$ impacts were 0.213 $\mu g/m^3$, well below the 1.0 $\mu g/m^3$ SIL.

Allowable emissions of annual $NO_2$ changed only for the engines powering the emergency generator. NAAQS compliance was demonstrated by using the previously performed SIL analysis to show that conservatively revised impacts are still below the SIL. Attachment 5 provides the details of the revisions to the analysis.

The total additive change in maximum annual $NO_2$ impacts was estimated by DEQ to be 0.012 $\mu g/m^3$. Adding this to the previously modeled facility-wide impact of 0.213 $\mu g/m^3$, gives a revised facility-wide impact of 0.225 $\mu g/m^3$. This is well below the 1.0 $\mu g/m^3$ SIL.

### 3.5 Results for Cumulative Impact Analyses

The modeling analyses supporting the originally issued permit showed that impacts of 1-hour CO could exceed the 2,000 $\mu g/m^3$ SIL, thereby requiring a cumulative NAAQS impact analysis. The maximum modeled facility-wide impact was 4,061 $\mu g/m^3$, well below the 40,000 $\mu g/m^3$ NAAQS.

Allowable emissions of 1-hour CO only changed for the engines powering the emergency generator and the fire water pump. NAAQS compliance was demonstrated by using the previously performed analysis, scaling source-specific impacts according to the ratio of increased emissions from the two sources. Attachment 6 provides the details of the revisions to the analysis.

The maximum change in CO source-specific impacts from the change in emissions is 87 $\mu g/m^3$. This compares to the CO SIL of 2,000 $\mu g/m^3$. The source specific increase in impacts was conservatively added to the previously modeled facility-wide impact of 4,061 $\mu g/m^3$, giving a revised total facility-wide impact of 4,148 $\mu g/m^3$. This approach is very conservative because the maximum facility-wide impacts are driven by impacts from the turbine stack and occur at a considerably different location than impacts from the fire water pump or the emergency generator.

The revised design value of 7,748 $\mu g/m^3$ was calculated by adding the revised facility-wide impact to the 3,600 $\mu g/m^3$ background concentration that was used for the previous modeling analyses. This value is well below the 40,000 $\mu g/m^3$ NAAQS.

### 3.6 Results for Toxic Air Pollutant Analyses

No TAP analyses were needed for the proposed project.

### 3.7 DEQ Verification Analysis Modeling

Results of the 24-hour $PM_{10}$ analyses were closer to the respective SIL threshold than were other pollutants, except for CO, where impacts were primarily driven by the emissions from the turbine stack. $PM_{10}$ impacts were largely driven by emissions from the cooling towers, with emissions from the storage silos having a measurable contribution. Both of these sources release emissions at a relatively low elevation compared to the turbine, making the positioning of the source critical for evaluating impacts to an ambient air boundary that is very close to the sources.

Characteristics of the emission sources, primarily the site location and release height of the storage silo vents and the location of downwash-inducing structures, changed substantially between what was modeled for the current permit and what was built and operated. Because of this, DEQ was less certain that the impact ratio method was adequately conservative in assuring $PM_{10}$ impacts will remain below the SIL threshold. To provide additional assurance that 24-hour $PM_{10}$ impacts will be below the SIL, DEQ revised the modeling input files and reran the model.

#### *3.7.1 Revisions to Model Input File*

Revisions to the 24-hour $PM_{10}$ model input consisted of: 1) correction of emission rates; 2) correction of emission release parameters (release height, flow rates, etc.); 3) correction of emission point locations; 4) correction of building and tank locations; and 5) change in the ambient air boundary.

## Emissions Rates

Emission rates used in the DEQ verification modeling analyses are provided in Table 5 for all sources except the main turbine stack. Emissions from the main turbine stack were unchanged from the modeling analyses performed for the current permit, modeled at 12.55 pounds per hour for 24-hour $PM_{10}$.

## Source Release Parameters

The changes in emission release parameters were described in Section 3.3 and are provided in Table 6.

**Table 6. EMISSION RELEASE PARAMETERS FOR DEQ VERIFICATION ANALYSES**

| Emission Point | Stack Height (m) | Stack Diameter (m) | Stack Gas Flow Rate (m/sec) | Stack Gas Temp (K) |
|---|---|---|---|---|
| Main Turbine Stack (HRSG1) | 48.8 | 5.49 | 17.47 | 362.8 |
| Cooling Tower Cell (CT1 – CT7)[a] | 14.2 | 10 | 9.97 | 298.2 |
| Lime Storage Silo (SILO1) | 19.9 | 0.61 | 1.62 | 310.9 |
| Magnesium Storage Silo (SILO2) | 12.6 | 0.61 | 1.62 | 310.9 |
| Soda Ash Storage Silo (SILO3) | 13.6 | 0.61 | 1.62 | 310.9 |
| Fire Water Pump (FP) | 6.1 | 0.13 | 52.4 | 789.3 |
| Emergency Generator (EG) | 6.1 | 0.15 | 163 | 786.4 |

[a] Parameters are identical for each of the seven cooling tower cells.

## Source and Building Locations

Figure 2 shows how the location of emission sources and structures in the modeling analyses supporting the current permit differed from what was actually constructed. Actual source and building locations are shown in the aerial photograph and the locations as modeled in the previous analyses are outlined in blue.

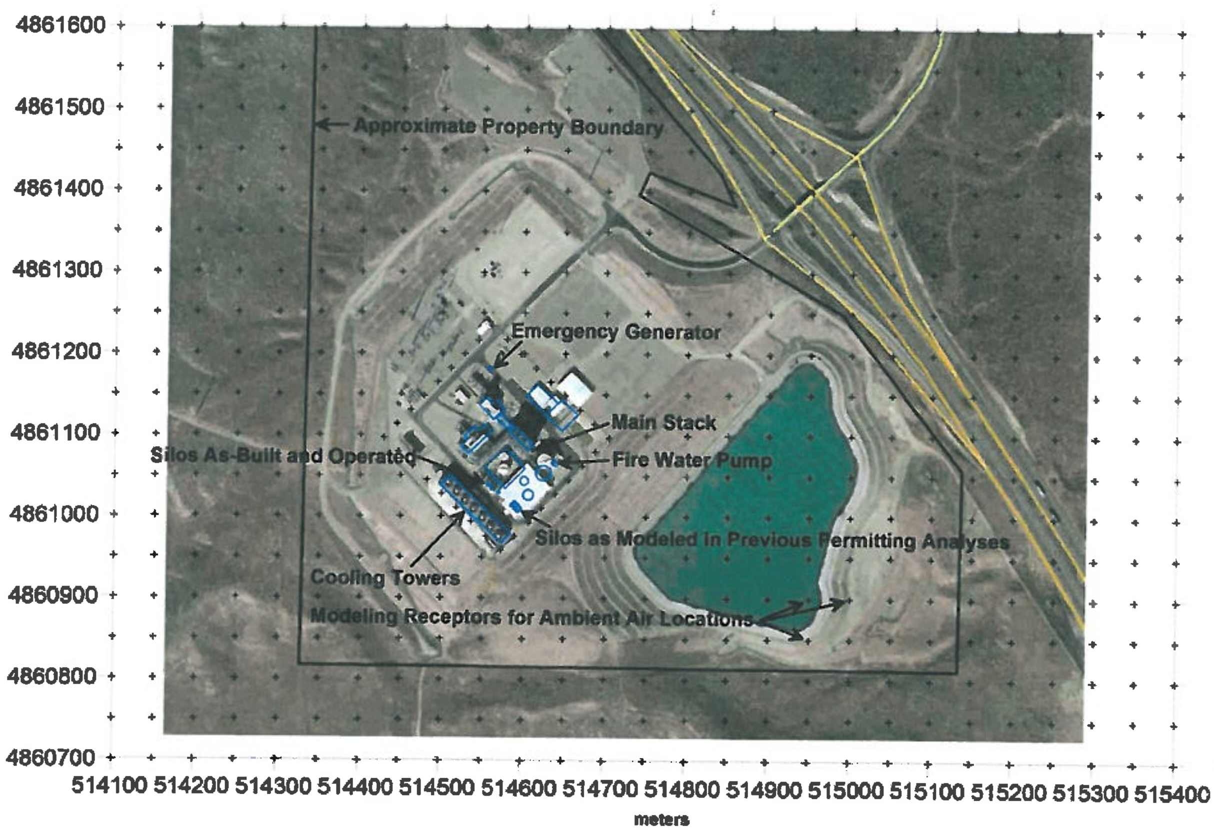
The most substantial difference observed in the figure is the change in the location and number of dry chemical storage silos. The location of the emergency generator also appeared to be different. Several buildings and tanks were constructed in substantially different locations than depicted in the model, which could alter plume downwash effects.

DEQ verification analyses did not completely or accurately correct the identified source/building location issues. DEQ revised the analysis by visually relocating sources and buildings to better match what was built, as indicated by the aerial photograph. DEQ did not obtain revised building coordinates verified by the applicant. The verification analysis was run to provide an idea of how changes in the source/building locations could potentially affect model results.

## Change in Ambient Air Boundary

IPC used an internal security fence as the ambient air boundary for the modeling analyses supporting the current permit. They have now indicated that the outer fence along the property boundary meets the definition of an ambient air boundary, effectively and legally precluding public access. The outer fence is approximated in Figure 2. There are many ambient air receptors located between the inner fence and the outer fence, as indicated in the figure. DEQ removed modeling receptors, indicated as "+" symbols in the figure, which were well inside of the outer fence for the verification analyses. This was only done for the southern part of the property since the northern part of the property was not where maximum $PM_{10}$ concentrations were predicted.

## Figure 2 – Actual Source and Building Locations vs. Modeled Locations

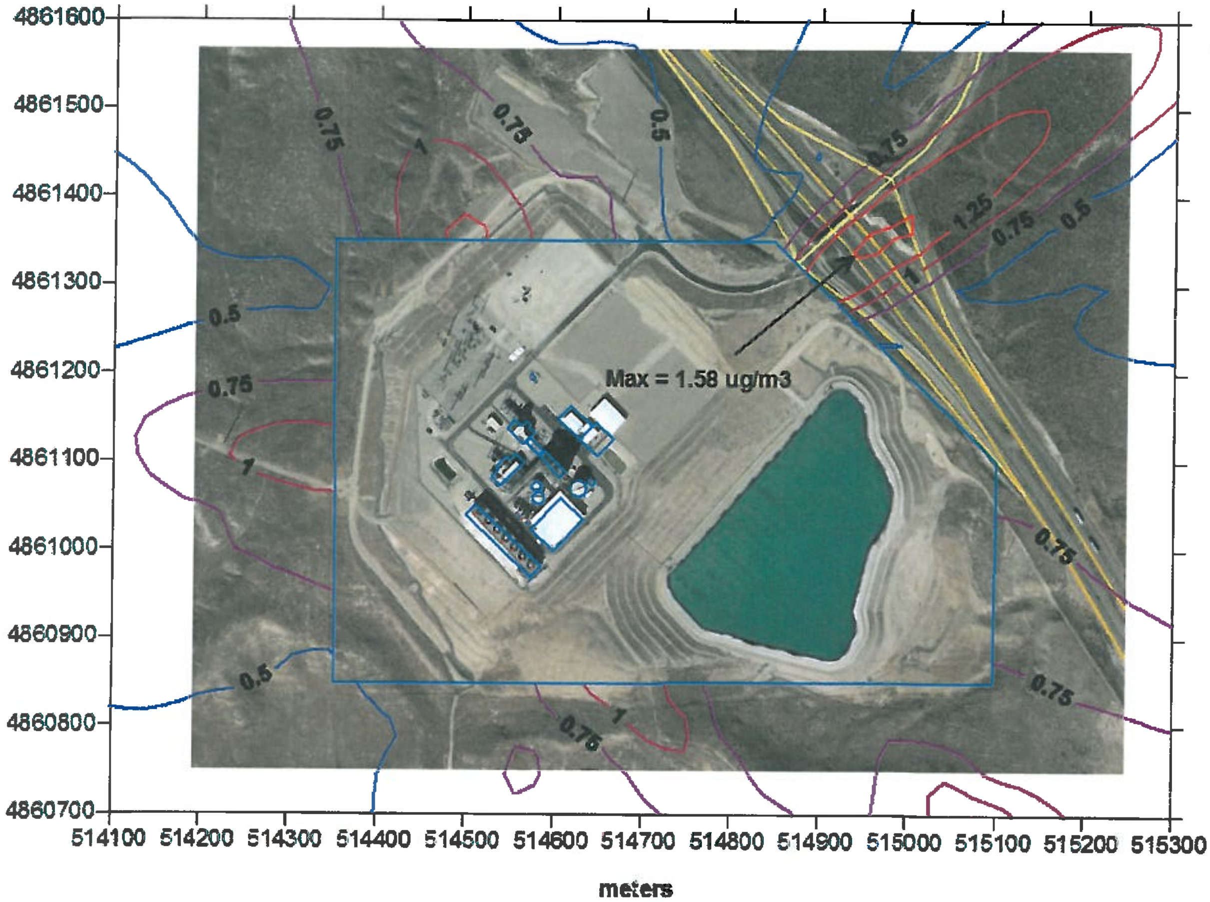



### *3.7.2 Results from DEQ Verification Analyses*

Figure 3 shows results from the DEQ 24-hour $PM_{10}$ verification analysis. The maximum 24-hour $PM_{10}$ concentration was predicted at 1.58 $\mu g/m^3$ at a location immediately northeast of the site. This value is less than the 1.87 $\mu g/m^3$ maximum $PM_{10}$ concentration from the analysis supporting the current permit, and it is much less than the 3.18 $\mu g/m^3$ impact conservatively calculated by using the emissions ratio method described in Section 3.4.2 and Attachment 3.

Although the model inputs of building dimensions and the ambient air receptors for the DEQ verification analyses were not highly accurate compared to what is typically used for permitting analyses, results from the verification analysis provides additional confidence that revisions in permit-allowable emissions and the deviations in site layout from what was used in preconstruction analyses will not result in ambient air impacts that exceed the SIL (except for 1-hour CO, which required a cumulative NAAQS analysis for the impact analysis supporting the current permit).

**Figure 3 – DEQ 24-Hour $PM_{10}$ Verification Analysis**




## 4.0 Conclusions

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the proposed permit revision project for LGPP would not cause or significantly contribute to a violation of any ambient air quality standard.

## Attachment 1 – $PM_{2.5}$ Emission Increases for Modeling Applicability

Table A1 provides a $PM_{2.5}$ emissions comparison between what was modeled in the analyses supporting the permit issued in 2010 and the revised emissions associated with this proposed permit revision.

**Table A1. $PM_{2.5}$ Emission Increases Summary for Modeling Applicability**

| Source | Averaging Period | Previously Modeled Emissions (lb/hr) | Revised Emissions (lb/hr) | Change in Emissions for Modeling Applicability (lb/hr) |
|---|---|---|---|---|
| Fire Water Pump | 24-hour | 0.00430 | 0.00833 | 0.00403 |
| | Annual | 0.000356 | 0.000457 | 0.000101 |
| Emergency Generator | 24-hour | 0.0606 | 0.0667 | 0.0061 |
| | Annual | 0.00249 | 0.00274 | 0.00025 |
| Cooling Tower Cells | 24-hour | 0.0949 x 7 cells | 0.1143 x 7 cells | 0.0194 x 7 cells = 0.1358 |
| | Annual | 0.0949 x 7 cells | 0.1143 x 7 cells | 0.0194 x 7 cells = 0.1358 |
| Chemical Storage Silos | 24-hour | 0.00714 x 6 silos | 0.01075 x 3 silos | 0.03225[a] |
| | Annual | 0.000235 x 6 silos | 0.000707 x 3 silos | 0.00212[a] |
| Total | 24-hour | 0.7720 | 0.9074 | 0.1785 |
| | Annual | 0.6686 | 0.8054 | 0.1383 (0.606 T/yr)[b] |

| Modeling Threshold | Averaging Period | Value | Modeling Threshold | Averaging Period | Value |
|---|---|---|---|---|---|
| Level 1 | 24-hour | 0.054 lb/hr | Level 2 | 24-hour | 0.63 lb/hr |
| | Annual | 0.35 T/yr | | Annual | 4.1 T/yr |
| Level 1 Threshold Exceeded | 24-hour | Yes | Level 2 Threshold Exceeded | 24-hour | No |
| | Annual | Yes | | Annual | No |

a. Previously modeled emissions not considered in change because the nature of the source (location and release parameters) changed substantially.

b. T/yr value based on 8,760 hours per year at the listed average annual lb/hr rate.

## Attachment 2 – Revised 8-Hour CO Impact Analyses

Table A2 provides the revised 8-hour CO cumulative NAAQS impact analysis results. The ratio of revised emissions to previously modeled emissions was used to scale maximum modeled impacts for the specific source. The change in maximum modeled impacts of the source was then determined and added to the previously modeled maximum impact of facility-wide CO emissions.

**Table A2. Revision of 8-Hour CO SIL Analyses**

| Source | Fire Water Pump | Emergency Generator | Total |
|---|---|---|---|
| Previously Modeled Emission Rate (lb/hr) | 0.252 | 3.152 | |
| Revised Emission Rate (lb/hr) | 0.425 | 3.500 | |
| Change in Emissions (lb/hr) | 0.173 | 0.348 | |
| Maximum Previously Modeled Impact of Source (μg/m$^3$) | 45.8 | 194.8 | |
| Modified Impact of Source[a] (μg/m$^3$) | 86.4 | 216.3 | |
| Change in Maximum Modeled Impact of Source (μg/m$^3$) | 40.6 | 21.5 | 62.1 |
| Previously Modeled Facility-Wide Maximum Impact (μg/m$^3$) | | | 194.8 |
| Conservatively Revised Facility-Wide Maximum Impact (μg/m$^3$) | | | 256.7[b] |
| SIL (μg/m$^3$) | | | 500 |

a. Based on multiplying the modeled impact by the ratio of revised emissions to modeled emissions.
b. Calculated by conservatively assuming the increase in impacts from each individual source will be additive for a combined impact. Because the two sources are not located near each other, they are not likely to both impact the same receptor at the same time.

# Attachment 3 – Revised 24-Hour $PM_{10}$ Impact Analyses

Table A3 provides the revised 24-hour $PM_{10}$ SIL analysis results. The ratio of revised emissions to previously modeled emissions was used to scale maximum modeled impacts for the specific source. The change in maximum modeled impacts of the source was then determined and added to the previously modeled maximum impact of facility-wide 24-hour $PM_{10}$ emissions.

**Table A3. Revision of 24-Hour $PM_{10}$ SIL Analyses**

| Source | Fire Water Pump | Emergency Generator | Cooling Tower Cells | Dry Chemical Storage Silos | Total |
|---|---|---|---|---|---|
| Previously Modeled Emission Rate (lb/hr) | 0.0043 | 0.0606 | 0.6642[a] | 0.00714[b] | |
| Revised Emission Rate (lb/hr) | 0.00833 | 0.0667 | 0.8000[a] | 0.01075[c] | |
| Change in Emissions (lb/hr) | 0.00403 | 0.0061 | 0.1358[a] | 0.00361[d] | |
| Maximum Previously Modeled Impact of Source ($\mu g/m^3$) | 0.362 | 1.022 | 1.535 | 0.3678[e] | |
| Modified Impact of Source[f] ($\mu g/m^3$) | 0.702 | 1.124 | 1.849 | 0.5538[g] | |
| Change in Maximum Modeled Impact of Source ($\mu g/m^3$) | 0.340 | 0.102 | 0.314 | 0.186[h]<br>0.558[i] | 1.314[j] |
| Previously Modeled Facility-Wide Maximum Impact ($\mu g/m^3$) | | | | | 1.87 |
| Conservatively Revised Facility-Wide Maximum Impact ($\mu g/m^3$) | | | | | 3.18 |
| SIL ($\mu g/m^3$) | | | | | 5.0 |

a. Total emissions for seven individual cells.
b. Emissions for one of six individual silos.
c. Emissions for one of three individual silos.
d. Change in emissions per silo.
e. Maximum impact from one silo (maximum of six silos).
f. Based on multiplying the modeled impact by the ratio of revised emissions to modeled emissions.
g. Modified change in impact per silo (three total).
h. Impact per each of three silos.
i. Total change in impact for source, using three silos.
j. Calculated by conservatively assuming the increase in impacts from each individual source will be additive for a combined impact. Because these sources are not located near each other, they are not likely to both impact the same receptor at the same time.

# Attachment 4 – Revised Annual $PM_{10}$ Impact Analyses

Table A4 provides the revised annual $PM_{10}$ SIL analysis results. The ratio of revised emissions to previously modeled emissions was used to scale maximum modeled impacts for the specific source. The change in maximum modeled impacts of the source was then determined and added to the previously modeled maximum impact of facility-wide annual $PM_{10}$ emissions.

**Table A4. Revision of Annual $PM_{10}$ SIL Analyses**

| Source | Fire Water Pump | Emergency Generator | Cooling Tower Cells | Dry Chemical Storage Silos | Total |
|---|---|---|---|---|---|
| Previously Modeled Emission Rate (lb/hr) | 0.000356 | 0.00249 | 0.6642[a] | 0.000235[b] | |
| Revised Emission Rate (lb/hr) | 0.000457 | 0.00274 | 0.8000[a] | 0.000707[c] | |
| Change in Emissions (lb/hr) | 0.000101 | 0.00025 | 0.1358 | 0.000472[d] | |
| Maximum Previously Modeled Impact of Source ($\mu g/m^3$) | 0.00763 | 0.00362 | 0.207 | 0.00338[e] | |
| Modified Impact of Source[f] ($\mu g/m^3$) | 0.00978 | 0.00398 | 0.249 | 0.01017[g] | |
| Change in Maximum Modeled Impact of Source ($\mu g/m^3$) | 0.00215 | 0.00036 | 0.042 | 0.00679[h]<br>0.02037[i] | 0.0649[j] |
| Previously Modeled Facility-Wide Maximum Impact ($\mu g/m^3$) | | | | | 0.2327 |
| Conservatively Revised Facility-Wide Maximum Impact ($\mu g/m^3$) | | | | | 0.30 |
| SIL ($\mu g/m^3$) | | | | | 1.0 |

a. Total emissions for seven individual cells.
b. Emissions for one of six individual silos.
c. Emissions for one of three individual silos.
d. Change in emissions per silo.
e. Maximum impact from one silo (maximum of six silos).
f. Based on multiplying the modeled impact by the ratio of revised emissions to modeled emissions.
g. Modified change in impact per silo (three total).
h. Impact per each of three silos.
i. Total change in impact for source, using three silos.
j. Calculated by conservatively assuming the increase in impacts from each individual source will be additive for a combined impact. Because these sources are not located near each other, they are not likely to both impact the same receptor at the same time.

## Attachment 5 – Revised Annual $NO_2$ Impact Analyses

Table A5 provides the revised annual $NO_2$ SIL analysis results. The ratio of revised emissions to previously modeled emissions was used to scale maximum modeled impacts for the specific source. The change in maximum modeled impacts of the source was then determined and added to the previously modeled maximum impact of facility-wide $NO_2$ emissions.

**Table A5. Revision of Annual $NO_2$ SIL Analysis**

| Source | Fire Water Pump | Emergency Generator | Total |
|---|---|---|---|
| Previously Modeled Emission Rate (lb/hr) | 0.00685 | 0.0799 | |
| Revised Emission Rate (lb/hr) | 0.00685 | 0.0879 | |
| Change in Emissions (lb/hr) | 0.0 | 0.0080 | 0.0080 |
| Maximum Previously Modeled Impact of Source ($\mu g/m^3$) | 0.147 | 0.116 | |
| Modified Impact of Source[a] ($\mu g/m^3$) | 0.147 | 0.128 | |
| Change in Maximum Modeled Impact of Source ($\mu g/m^3$) | 0.0 | 0.012 | 0.012 |
| Previously Modeled Facility-Wide Maximum Impact ($\mu g/m^3$) | | | 0.213 |
| Conservatively Revised Facility-Wide Maximum Impact ($\mu g/m^3$) | | | 0.225 |
| SIL ($\mu g/m^3$) | | | 1 |

a. Based on multiplying the modeled impact by the ratio of revised emissions to modeled emissions.

# Attachment 6 – Revised 1-Hour CO Impact Analyses

Table A5 provides the revised 1-hour CO cumulative NAAQS impact analysis results. The ratio of revised emissions to previously modeled emissions was used to scale maximum modeled impacts for the specific source. The change in maximum modeled impacts of the source was then determined and added to the previously modeled maximum impact of facility-wide CO emissions.

**Table A6. Revision of 1-Hour CO Cumulative NAAQS Impact Analyses**

| Source | Fire Water Pump | Emergency Generator | Total |
|---|---|---|---|
| Previously Modeled Emission Rate (lb/hr) | 1.80 | 6.30 | |
| Revised Emission Rate (lb/hr) | 1.70 | 7.00 | |
| Change in Emissions (lb/hr) | -0.10 | 0.70 | |
| Maximum Previously Modeled Impact of Source ($\mu g/m^3$) | 945.6 | 781.7 | |
| Modified Impact of Source[a] ($\mu g/m^3$) | 893.0 | 868.6 | |
| Change in Maximum Modeled Impact of Source ($\mu g/m^3$) | -52.6 | 86.9 | 86.9 |
| Previously Modeled Facility-Wide Maximum Impact ($\mu g/m^3$) | 4,061 | 4,061 | 4,061 |
| Conservatively Revised Facility-Wide Maximum Impact ($\mu g/m^3$) | 4,061[b] | 4,148[c] | 4,148 |
| NAAQS ($\mu g/m^3$) | 40,000 | 40,000 | 40,000 |
| Combined Impact of Previously Modeled Facility and Co-Contributing Sources ($\mu g/m^3$) | | | 4,061[d] |
| Background Concentration ($\mu g/m^3$) | | | 3,600 |
| Total Revised Design Value ($\mu g/m^3$) | | | 7,748[e] |

a. Based on multiplying the modeled impact by the ratio of revised emissions to modeled emissions.

b. There is not likely to be a decrease in the maximum impact because the maximum impact results from emissions of the turbine, and the maximum impact of the fire water pump is in a different location because of the differences in dispersion-affecting parameters (stack height, downwash from buildings, flow rate, etc.).

c. This estimate is very conservative because the facility-wide maximum impact is at a location substantially different from where the emergency generator has a maximum impact.

d. This value is identical to the impacts of the facility without co-contributing sources because co-contributing sources impact receptors at a different location and/or time than where/when the facility has a maximum impact.

e. Total of previously modeled impact of facility and co-contributing sources, the conservatively estimated change in source-specific impacts, and the background concentration.