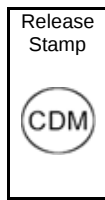
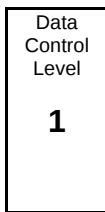


SPECIFICATION

FUEL, AIR, WATER (OR STEAM) & COMPRESSOR CLEANING FLUIDS FOR SOLAR® GAS TURBINE ENGINES



SPECIFICATION NO. ES 9-98

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1.0 SCOPE - This specification establishes the quality requirements for the fuel, air, water (or steam) and compressor cleaning solutions to be used in *Solar* gas turbine engines.

This specification supersedes all previous Solar fuel, air, or water specifications, including fuel specification ES 1211, ES 9-247, and ES 9-251, for use in *Solar* gas turbine operation.

1.1 RESPONSIBILITY/DEVIATIONS - It is the responsibility of the end user to ensure that where required by this specification, Solar Turbines' approval has been sought for use of the fluids cited. It is also the responsibility of the end user to ensure on a continuing basis that all fluids entering the gas turbines are compliant with this specification. Deviations from the limits and requirements herein shall not be considered without consultation and specific written approval from Solar Engineering. These approvals can be attained through the Special Engine Request Process.

2.0 APPLICABLE DOCUMENTS - The following documents, of issue in effect on the date of this specification, shall be a part of this specification to the extent specified herein.

Solar Specifications

ES 9-62	Ingestive Cleaning Solar Turbine Engines
ES 2069	Set-up, Installation, and Operating Instructions for Evaporative Coolers
ES 2707	Standard Air Sampling, Site and Laboratory Testing Requirements for TAI Filtration System

Solar Forms

FORM 2594	Liquid Fuel Suitability Inquiry
FORM 2595	Gaseous Fuel Suitability Inquiry
FORM 3091	Total Site Contamination Worksheet

Product Information Letters

PIL 162	Recommendations and Requirements for the Sourcing, Handling, Storage and Treatment for Gas and Liquid Fuels Used for Gas Turbines
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American Society for Testing and Materials

ASTM D86	Method of Test for Distillation of Petroleum Products
ASTM D93	Method of Test for Flash Point by Pensky - Martens Closed Tester
ASTM D97	Method of Test for Pour Points
ASTM D130	Method of Test for Copper Corrosion by Petroleum Products, Copper Strip Test
ASTM D240	Method of Test for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter
ASTM D323	Method of Test for Vapor Pressure of Petroleum Products (Reid Method)
ASTM D445	Method of Test for Viscosity of Transparent and Opaque Liquids (Kinematic and Dynamic Viscosities)
ASTM D482	Method of Test for Ash from Petroleum Products
ASTM D511	Tests for Calcium and Magnesium in Water
ASTM D512	Standard Test Method for Chloride Ion in Water
ASTM D664	Standard Test Method for Acid Number of Petroleum Products by Potentiometric Titration
ASTM D524	Method of Test for Ramsbottom Carbon Residue of Petroleum Products
ASTM D808	Tests for Chlorine in New and Used Petroleum Products (Bomb Method)
ASTM D859	Tests for Silica in Water
ASTM D1072	Test for Total Sulfur in Fuel Gases
ASTM D1179	Standard Test Methods for Fluoride Ion in Water
ASTM D1253	Tests for Residual Chlorine in Water
ASTM D1266	Sulfur in Petroleum Products and liquefied Petroleum Gases (Lamp Method)
ASTM D1267	Vapor Pressure of Liquefied Petroleum Gases

ASTM D1293	Tests for pH of Water
ASTM D1298	Density, Specific Gravity or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1319	Method of Test for Hydrocarbon Types in Liquid Petroleum Products by Fluorescent Indicator Absorption
ASTM D1657	Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer
ASTM D1838	Copper Strip Corrosion by Liquefied Petroleum Gases
ASTM D2163	Analysis of Liquefied Petroleum Gases by Gas Chromatography
ASTM D2500	Method of Test for Cloud Point
ASTM D2598	Calculation of Physical Characteristics of Liquefied Petroleum Gases from Compositional Analysis
ASTM D2622	Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence
ASTM D3605	Trace Metals in Gas Turbine Fuels by Atomic Absorption and Flame Emission Spectroscopy
ASTM D3373	Tests for Vanadium in Water
ASTM D3559	Tests for Lead in Water
ASTM D3868	Standard Test Methods for Fluoride Ion in Brackish Water, Seawater, and Brines
ASTM D3919	Standard Practice for Measuring Trace Elements in Water by Graphite Furnace Atomic Absorption Spectrophotometry
ASTM D4052	Standard Test Method for Density and Relative Density by Digital Density Meter
ASTM D4192	Standard Test Method for Potassium in Water by Atomic Spectrophotometry
ASTM D4294	Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy Dispersive X-ray Fluorescence Spectrometry
ASTM D4418	Standard Practice for Receipt, Storage, and Handling of Fuels for Gas Turbines
ASTM D4629	Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection
ASTM D5186	Test Method for Determination of Aromatic Content of Diesel Fuels by Supercritical Fluid Chromatography
ASTM D5453	Determination of Total Sulfur in Light Hydrocarbons
ASTM D5673	Standard Test Method for Elements in Water by Inductively Coupled Plasma Spectrometry
ASTM D5762	Standard Test method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence
ASTM D5907	Standard Test Method for Filterable and non-Filterable Matter in Water
ASTM D6079	Evaluating Lubricity of Diesel Fuels by High-Frequency Reciprocating Rig (HFRR)
ASTM D6217	Standard Test Method for Particulate Contamination in Middle Distillate Fuels
ASTM D6304	Standard Test Method for Determination of Water in Petroleum Products
ASTM D6584	Standard Test Method for Determination of Total Monoglycerides, Total Diglycerides, Total Triglycerides, and Free and Total Glycerin in Biodiesel Methyl Esters by Gas Chromatography
ASTM D6591	Standard Test Method for Determination of Aromatic Hydrocarbon Types in Middle Distillates
ASTM D7111	Determination of Trace Elements in Middle Distillate Fuels by Inductively Coupled Plasma Atomic Emission Spectrometry (ICP-AES).

ASTM D7220	Standard Test Method for Sulfur in Automotive, Heating, and Jet Fuels by Monochromatic Energy Dispersive X-ray Fluorescence Spectrometry
ASTM D7371	Standard Test Method for Determination of Biodiesel (Fatty Acid Methyl Esters) Content in Diesel Fuel Oil Using Mid Infrared Spectroscopy (FTIR)
ASTM D7800	Standard Test Method for Determination of Elemental Sulfur in Natural Gas.

European/British Standards

EN 4110	Determination of Methanol Content (British Standard)
EN 14112	Determination of Oxidation Stability (Accelerated Oxidation Test) (British Standard)

Air Filter Efficiency Test Specifications

ASHRAE 52.2	Method of Testing General Ventilation Air-Cleaning Devices for Removal Efficiency by Particle Size
EN 779	Particulate Air Filters for General Ventilation — Determination of the Filtration Performance (ISO 16890 replaced EN 779)
EN 1822	High Efficiency Air Filters (EPA, HEPA and ULPA)

Natural Gas Processors Association

NGP 2140-70	Liquefied Petroleum Gas Specifications and Test Methods
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Deutsches Institute Fur Normung (DIN)

DIN 51850	Gross and Net Calorific Value of Pure Gaseous Fuels
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US Bureau of Mines

Bulletin 627	Flammability Characteristics of Combustible Gases and Vapors
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International Organization for Standardization (ISO)

ISO 8537-1	Compressed Air- Part 1: Contaminants and purity classes
ISO 16890	Air Filters for General Ventilation

3.0 GENERAL REQUIREMENTS - The requirements stated herein govern the quality of air, fuel, and water (steam) entering the engine. Failure to meet the requirements in this specification can result in a negative impact on the performance and life expectations of the engine and package.

3.1 UNDESIRABLE CONTAMINANTS - The contaminants listed here are known to be harmful to engine components and must be controlled to within the maximum allowable limits specified for each contaminant in order to attain maximum engine life. The total quantity of each contaminant ingested by the engine must be limited regardless of whether it enters through the air, fuel, injected water (steam), or as liquid water carryover from evaporative cooling.

The limits for each of the several critical contaminants from all possible sources are provided in Table 1.

3.2 SOURCES OF CONTAMINATION – There are four major potential sources of contamination - air, fuel (gas, liquid, or solid), injected water/steam (for continuous NO_x control) and liquid water carryover from the evaporative cooler (if used). Minor sources of contamination include water for compressor cleaning, water for dual fuel injector purging, and compressor cleaning fluids have also been identified.

In order to effectively control the quality of air, fuel, and water entering the engine as defined in this Specification, Solar's Package Engineering Department shall be consulted in specifying treatment and cleanup systems for the major sources, while the minor sources must meet the quality specified in Tables 4 and 5 of this document.

Table 1. Maximum Allowable Contaminant Concentrations

Contaminant	Limit ^(Note 1) in Fuel Equivalent Concentrations	Test Method
Sulfur (see Notes 2, 3, & 4)	10,000 ppmw FEC (See note 5A, 5B, 5C & 6). Additional restrictions apply for SoLoNOx liquid operation (See note 6)	ASTM D1072, D1266, D2622, D4294, D5453 or D7220.
Sodium + Potassium	0.5 ppmw FEC	ASTM D3605 or D7111
Vanadium	0.5 ppmw FEC	ASTM D3605, D3373 or D7111
Lead	1 ppmw FEC	ASTM D3605, D3559 or D7111
Calcium + Magnesium	2 ppmw FEC	ASTM D3605, D511 or D7111
Fluorine	1 ppmw FEC	ASTM D1179, D3868
Chlorine	0.15 weight percent or 1,500 ppmw FEC	ASTM D512, D808, D1253,
Others (See Notes 7 & 8)	0.5 ppmw FEC	
Notes: (1) The limits given are FUEL EQUIVALENT CONCENTRATIONS (FEC), i.e., the maximum allowable concentration of each contaminant as if each contaminant is found solely in a fuel with LHV - 18,380 Btu/lb. (such as diesel #2). Instructions for performing calculations are provided in Appendix A, Form 3091, Total Site Contamination Worksheet. (2) For installations with exhaust heat recovery equipment, it is important to maintain sulfur levels at below the SO ₃ dew point. Because conversion from SO ₂ to SO ₃ in the combustor is a function of several factors that are not readily definable, it is recommended that fuel sulfur is limited to less than 0.5% weight FEC. This value is based on 60:1 air-to-fuel ratio at up to 17% conversion for an acid dew point of 240°F. (3) If sulfur is present in the form of hydrogen sulfide, appropriate precautions must be taken to detect leaks because of the highly toxic nature of this gas even in trace quantities. High sulfur fuels (exceeding limits) may be used with special provisions; however, such fuels must be reviewed and approved in writing by Engineering prior to use. (4) U.S. Federal and local Air Pollution control districts may require lower limits for sulfur. (5A) Harsh environment protection hardware and ancillary equipment is required for gas fuel with H ₂ S concentration greater than 3000 ppmw FEC or liquid fuel with sulfur concentration more than 2000 ppmw FEC. (5B) Sites with alkali-laden air (Marine, salt beds, salt mines), poor ambient air quality or proximity to sulfur sources require harsh environment protection hardware regardless of sulfur levels. (5C) Higher sulfur levels (> 10,000 ppmw FEC) can be considered for a specific application and must be approved in writing by engineering. (6) Liquid fuel sulfur content limits and specific fuel handling and storage requirements are required for SoLoNOx liquid fuel operation. Low emissions on diesel fuel require lower sulfur limits. Restrictions do not apply to kerosene or jet fuel A. See section 10.1. (7) The following contaminants are unlikely to be present except in unusual or accidental contamination of air, fuel or water supplies. However, if detected at levels greater than 0.5 ppmw FEC fuel equivalent, special treatment and precautions are required. Mercury – Cadmium – Bismuth – Arsenic – Indium – Antimony – Phosphorous – Boron - Gallium –Aluminum + Silicon. (8) Any other trace element with concentrations over 0.5 ppmw FEC fuel equivalent should be discussed with, and reviewed, by Engineering.		

3.3 DETERMINATION OF TOTAL CONTAMINANTS - The total concentration of each of the major potential sources of contaminants entering the engine can be determined by using the equations provided here.

For direct fired applications:

$$\text{Total Contaminant} = \frac{18,380}{\text{LHV}} \times [(\text{AFR})A + F + (\text{WFR})W + (\text{CFR})C]$$

For indirect fired applications:

$$\text{Total Contaminant} = 65 \times [A + (\text{WAR})W + (\text{CAR})C]$$

Where:

Total Contaminant = total concentration of that particular contaminant, ppmw fuel equivalent (for indirect fired applications, total contaminant is expressed as ppmw air equivalent concentration, normalized to 65 air-to-fuel ratio.

LHV = lower heating value of fuel, Btu/lb

AFR* = air-to-fuel mass ratio

A = concentration of that particular contaminant in air entering the engine, ppmw in air

F = concentration of that particular contaminant in fuel, ppmw in fuel

WFR* = water-to-fuel mass ratio

W = concentration of that particular contaminant in injected water, ppmw in water

CFR* = carryover water-to-fuel mass ratio

C = concentration of that particular contaminant in evaporative cooler water (or feed water), ppmw in water

WAR = water-to-air mass ratio

CAR = carryover water-to-air mass ratio

* Fuel ratios are based on actual fuel rather than combustible fuel

A worksheet (Form 3091) with instructions for performing the above calculation is provided in Appendix A. (Derivation of the above equation for directly fired applications and the functional equation used in Form 3091 are included in Appendix B.)

3.4 ADDITIVES - Chemicals can be added to fuel and water treatment systems for specific purposes, e.g., softening, settling out of particulates, inhibition of organic growths, etc. Caution should be exercised to ascertain that the additives are not comprised of critical elements listed in Table 1 and that the maximum allowable limits specified are complied with.

3.5 CUSTOMER SITE DATA REQUIREMENTS - Information as to the condition and quality of the air, water (including steam), and fuel to be ingested by the engine, and other environmentally influenced conditions such as ambient temperature and humidity ranges is required by Solar to adequately define the necessary combustion system configuration, engine controls, settings, protective coatings, devices and operating procedures.

3.5.1 SAMPLING - Sampling and analyses of air, fuel, and water must be performed according to the specified test methods. Unless specifically instructed otherwise, all sampling should be performed at locations just upstream of the engine.

3.5.2 ADDITIONAL SITE DATA - The following information, if available, is required for all installations:

- Ambient temperature range
- Ambient humidity range
- Altitude
- Type of environment (rural, agricultural, residential, arctic, industrial, offshore, marine, coastal, desert, semi-arid, or tropical)
- Fuel conditions (fuel temperature and pressure ranges)

4.0 AIR

4.1 AIR QUALITY - Air borne constituents such as gases, liquid droplets and solid particles, can contain undesirable contaminants that are considered harmful. Adequate air filtration must be used to remove the bulk of such air borne constituents including water carryover from evaporative cooler applications. The combined concentration of contaminants from air, fuel and water (steam) shall meet the requirements of paragraph 3.1 and the maximum limits specified in Table 1.

4.1.1 ADDITIONAL LIMITS - Air used for pulsing self-cleaning air cleaner shall meet the requirements of ISO 8573, Class 4.

4.2 CONCENTRATION OF AIR BORNE CONTAMINANTS - Air borne contaminants constitute only one of several means by which contaminants enter the turbine engine. The minimum air quality allowed depends on the quality of the other fluids, such as injected water, fuel, and water carryover (if applicable). In order to assess the impact of air borne contaminant(s) on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each air borne contaminant can be calculated using the following function.

$$\text{Concentration in air, ppmw FEC} = \text{AFR} \times \frac{18380}{\text{LHV}} \times A (1-N)$$

Where:

- AFR= air-to-fuel ratio
- LHV= lower heating value, Btu/lb.
- A = concentration in ambient air, ppmw
- N = air cleaner efficiency, expressed as value 0.999 (99.9%)

4.2.1 CONCENTRATION GUIDELINES FOR AIR BORNE CONTAMINANTS - In general, air borne contaminants are expected to contribute less than 20% of the total concentration allowed except when air and fuel are the two fluids present. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for air borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

**Table 2. Guidelines for Contaminant Concentrations
(for nominal operating conditions with natural gas fuel)**

Available Sources	Air Borne Contaminants (% of Total)	Fuel Borne Contaminants (% of Total)	(Inj.) Water Borne Contaminants (% of Total)	Contaminants From E/C Carryover (% of Total)
Air + Fuel	<70	<10	0	0
Air + Fuel + Inj. Water	<20	<10	<50	0
Air + Fuel + Inj. Water + E/C	<20	<10	<20	<30
Air + Fuel + E/C	<20	<10	0	<50
Note: These values are provided only as guidelines and they are based on experience at Solar. Because of the inexactness of some of the values involved in the calculations, a 20% margin is built in to the numbers provided here.				

4.3 SITE SPECIFIC CONTAMINANTS IN AIR - If ambient air at a particular site is known to be of poor quality, based on prior experience or influence of industries and/or activities in the vicinity, consult with Package Engineering to ascertain compliance with all the requirements of this specification.

4.4 MINIMUM AIR FILTER PARTICLE REMOVAL EFFICIENCY REQUIREMENTS - Filters used in air cleaners installed in the combustion air inlet systems of Solar gas turbine packages must meet a minimum airborne particle removal efficiency of ISO ePM₁ 85 % (ISO 16890 replaced European standard EN 779, Grade F9) or MERV 15 (U.S. standard ASHRAE 52.2). In harsh environments having air borne and fuel borne contaminant concentrations too high to meet the guidelines in Table 2 using ISO ePM₁ 85 % or MERV 15 filters, filters must have a minimum particle removal efficiency of E10 (European standard EN 1822). Note that this information is provided for the purpose of considering filters based on their efficiency in the context of calculations employed to evaluate the contaminant concentration limits expressed in this Engineering Specification. It does not imply that any filter meeting these particle removal efficiencies also meets other filter performance requirements of Solar Turbines Incorporated.

5.0 INJECTED WATER (OR STEAM)

5.1 WATER QUALITY FOR WATER INJECTION TO REDUCE NO_x - The quality of water injected into the combustor for NO_x control must meet the general requirements defined in Section 3.1 as well as the specific requirements described in Table 3.

Table 3. Additional Quality Requirements for Water Injection

Parameter	Requirement	Test Method
pH	5.5 to 8.5	ASTM D1293
Suspended Solids	≤2.6 mg/liter of sediment, solid or hard contaminants, 90% of the 2.6 mg shall be less than 5 micron in size. Max allowable size ≤ 10 micron.	ASTM D5907; ISO 11923
Dissolved Silica	<0.1 ppmw SiO ₂ (<0.1 mg/l)	ASTM D859
Electrical Conductivity	≤5 μS/cm	ASTM D5391

5.2 CONCENTRATION OF (INJECTED) WATER BORNE CONTAMINANTS - Water borne contaminants from injected water/steam constitute only one of several means by which contaminants enter the turbine engine. The minimum water quality allowed depends on the quality of the other fluids, such as air, fuel, and water carryover (if applicable). In order to assess the impact of water borne contaminant(s) from injected water/steam on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each water borne contaminant can be calculated using the following function.

$$\text{Concentration in water, ppmw FEC} = \text{WFR} \times \frac{18380}{\text{LHV}} \times W$$

Where:

WFR	=	water-to-fuel ratio
LHV	=	lower heating value, Btu/lb
W	=	concentration of contaminant in injected water, ppmw

5.2.1 CONCENTRATION GUIDELINES FOR (INJECTED) WATER BORNE CONTAMINANTS - In general, water borne contaminants from injected water are expected to contribute less than 50% of the total concentration allowed. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for injected water (steam) borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

5.3 BOILER FEEDWATER - In general, boiler feed water is not suitable for use in water injection; additional treatment to remove dissolved and suspended contaminants is usually required to satisfy all the requirements of this specification.

5.4 OPERATION - It is recommended that Package Engineering is consulted in selecting appropriate equipment for treatment water. Continuous monitoring of water quality is strongly recommended with an alarm or automatic shutdown device installed between the final stage of treatment and the fuel injector manifold. The trip point shall be set to ensure that water entering the combustor is within the allowable limits of this specification.

5.5 WATER FOR INJECTOR PURGE AND COMPRESSOR CLEANING – Water is used in small quantities from time to time (not continuous operation), to either aid cleaning the compressor or to purge liquid fuel passages in dual fuel injectors during fuel transfers and liquid fuel shutdown. It has been determined that the contaminant limits for the water can be higher for these duties because the consumption is small and Table 4 shows the limits for the particular application.

Table 4. Contaminant Limits For Short Duration Water Ingestion Duties

	Test Method	Max. Limits for On-Crank Cleaning	Max. Limits for On-Line Cleaning	Max. Limits for Dual Fuel Injector Water Purge
Sodium + Potassium	ASTM D1428	105 ppmw	1.9 ppmw	1.9 ppmw
Fluorine	ASTM; D1179	100 ppmw	1.9 ppmw	1.9 ppmw
Chlorine	ASTM D512	100 ppmw	40 ppmw	40 ppmw
Lead	ASTM D3559	2 ppmw	0.70 ppmw	0.70 ppmw
Vanadium	ASTM D3373	2 ppmw	0.35 ppmw	0.35 ppmw
Iron, Tin, Silicon, Aluminum, Copper, Manganese, Phosphorus	ASTM D857, D858, D1068, D1688	10 ppmw	3.8 ppmw	3.8 ppmw
Calcium + Magnesium	ASTM D3605, D511	100 ppmw	3.8 ppmw	3.8 ppmw
Total Dissolved Solids	ASTM D1888	350 ppmw	5 ppmw	30 ppmw
Suspended solids	ASTM D5907	2.6 mg/l	2.6 mg/l	2.6 mg/l
Maximum particle size		10 microns	10 microns	10 microns
90% of particles		5 microns	5 microns	5 microns
Dissolved Silica		0.1 mg/l SiO ₂	0.1 mg/l SiO ₂	0.1 mg/l SiO ₂
PH	ASTM D1293	6 - 9	6 - 9	6 - 9
Electrical Conductivity		540 µS/cm	8 µS/cm	50 µS/cm

6.0 EVAPORATIVE COOLER WATER

6.1 GENERAL - For operation in hot and dry environments, evaporative cooling is commonly employed for power augmentation. The design/selection, installation and maintenance of evaporative cooler equipment are critical to engine operation and longevity and also affect the extent of water carryover into the airstream. Appropriate treatment of feed water must be specified in order to comply with the total requirements of this specification.

6.1.1 EVAPORATIVE COOLER EQUIPMENT - Instructions for set-up, installation and operation of evaporative coolers are provided in Engineering specification ES 2069.

6.1.2 DEIONIZED WATER - Do not use deionized water unless the evaporative cooler has been specially designed for it. The use of deionized water will require the use of stainless steel construction and binder reinforced media.

6.1.3 SOFT WATER - Soft water is usually high in sodium salts and low in calcium and magnesium salts. Therefore, soft water cannot be used for evaporative cooling unless it can be proven that sodium + potassium (and any other dissolved salts present) are in compliance with the requirements of Section 3.1.

6.2 CONCENTRATION OF CONTAMINANTS IN WATER CARRYOVER - Contaminants from evaporative cooler water carryover constitute only one of several means by which contaminants enter the turbine engine. The minimum evaporative cooler water quality allowed depends on the quality of the other fluids, such as air, fuel, and injected water. In order to assess the impact of contaminant(s) from evaporative cooler water carryover on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each contaminant can be calculated using the following function.

$$\text{Concentration in water carryover, ppmw FEC} = C \times \frac{R}{f} \times 9.2$$

Where:

- C = concentration in water delivered to header of evaporative cooler, ppmw (for recirculating system, C = concentration in reservoir; for non-recirculating system, C = concentration of feed water)
- R = carryover rate, gallons per minute (see Section 6.2.2)
- f = fuel flow rate, MBtu/hour (10^6 Btu/hour)

6.2.1 CONCENTRATION GUIDELINES FOR CONTAMINATION IN EVAPORATIVE COOLER WATER - In general, contaminants from evaporative cooler carryover are expected to contribute less than 50% of the total concentration allowed. Depending on the type of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for water carryover contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline. (Refer to ES 2069 for details on evaporative cooler installation and operation.)

6.2.2 WATER CARRYOVER RATE - Water carryover rate is the rate of water entering the combustion air inlet ducting through the evaporative cooler mist eliminator. An evaporative cooler that is properly designed, manufactured, installed, maintained, and operated, will not contribute water droplets to the combustion inlet air. However, experience has demonstrated that small amounts of water will enter the air stream from the evaporative cooler media, so all evaporative coolers used by Solar Turbines Inc. include a mist eliminator on the downstream side of the cooler. Mist eliminators used on these evaporative coolers supplied by Solar Turbines Incorporated have a drop limit size of 50 micron, which means that they are 99.9% efficient in removing water droplets as small as 50 microns. Because of the low air flow rate through the media (nominally 625 ft/min.) water droplets entrained in the air leaving the media surface are much larger than 50 micron. The recommended water carry over rate to be used in these calculations for all product lines is given below. The water carry over rates given in the table assume that a mist eliminator having an efficiency of not less than 99.9% on 50 micron water droplets is installed on the evaporative cooler. Nevertheless, the general requirements in Paragraph 3.1 include evaporative cooler water carryover as a potential source of contamination. Evaporative coolers without a mist eliminator having an efficiency of at least 99.9% on 50 micron water droplets are not approved for use on gas turbines manufactured by Solar Turbines Incorporated. The estimated evaporative cooler water carry over rate for all packages (C40, C50, M50, T60, T65, T70, M90, M100, T130 and T250) is 0.1 gallons per minute (GPM).

6.3 ADDITIONAL LIMITS FOR EVAPORATIVE COOLER WATER

Limits

pH	6-9
Turbidity	≤5,000 turbidity units (also known as Jackson units)
Hardness	160 ppmw CaCO ₃

6.4 OTHER CONTAMINANTS - Algae, aromatic hydrocarbons, oils, grease and wetting/dispersing agents such as phosphates can be harmful to the evaporative cooler media pad. Precautions must be exercised to prevent the formation or introduction of these contaminants into the feed water.

7.0 COMPRESSOR CLEANING FLUIDS

7.1 COMPRESSOR CLEANING PRODUCT QUALITY – Composition and physical properties of cleaning products must comply with the limits defined in Table 5. Failure to comply with these limits can cause corrosive attack and/or other harmful effects resulting in rapid engine deterioration. When the cleaning product consists of a mixture of cleaning solution concentrate and water, the limits in Table 5 apply to the resulting cleaning product.

Table 5. Requirements for Cleaning Product Used in Ingestive Cleaning of Solar Engines

	Test Method	Max. Limits for On-Crank Solutions	Max. Limits for On-Line Solutions
Sodium + Potassium	ASTM D1428	105 ppmw	1.9 ppmw
Fluorine	ASTM D1179	100 ppmw	1.9 ppmw
Chlorine	ASTM D512	100 ppmw	40 ppmw
Lead	ASTM D3559	2 ppmw	0.70 ppmw
Vanadium	ASTM D3373	2 ppmw	0.35 ppmw
Iron, Tin, Silicon, Aluminum, Copper, Manganese, Phosphorus	ASTM D857, D858, D1068, D1688	10 ppmw	3.8 ppmw
Calcium + Magnesium	ASTM D3605 ASTM D511	100 ppmw	3.8 ppmw
Ash	ASTM D482	0.25 wt. %	0.01 wt. %
Flash Point	ASTM D93	>140°F	>140°F
PH	ASTM D 1293	6 - 9	6 - 9

8.0 FUEL

8.1 GASEOUS FUELS - In general, gaseous fuels, which meet the limits in Table 6, can be used in standard fuel systems. The fuels must be free from condensed hydrocarbons, oils or water. Fuels, which do not meet these limits, must be reviewed by Solar. If judged suitable for use, control and/or combustor modifications will generally be required.

Table 6. Definitions of Gaseous Fuels for Use with a Standard Fuel System

Physical and Chemical Descriptions	ES9-98 Limits
Fuel Volume Ratio (1220/WOBBE Index*)	0.9 to 1.1
Fuel Mass ratio (21550/LHV Btu/lb)	<5
Hydrogen Content	<4% by volume
Carbon Monoxide Content**	<12.5% by volume
Hydrogen Sulfide**	10,000 ppmw Max. (See Table 1)
Ratio of Flammability Limits Upper flammability limit *** Lower flammability limit	>2.2 for Saturn >2.8 for Centaur and Mars
Stoichiometric Flame Temperature with Air Temperature Equal to Compressor Discharge Temperature at Design Point	>3600°F (1980°C)
Total Particulates	<30 ppmw x (LHV/21500)
Maximum Particle Size	10 micron
Fuel Gas Supply Temperature ¹ (at inlet flange of package)	No less than the greater of dew point temperature + 50°F for natural gas liquids or dew point temperature + 20°F for water.
	Greater than or equal to - 40°F and less than or equal to 200°F.
	Greater than or equal to 130°F for fuels containing elemental sulfur.
	Greater than or equal to 130°F for Titan 250 SoLoNOx combustion systems.
*WOBBE Index = Lower Heat Value (use ASTM 3588 or DIN 51850 for individual component heating values) in Btu/Scf divided by the square root of the relative density (specific gravity). **If carbon monoxide or hydrogen sulfide are present in the fuel gas, precautions must be taken to detect leaks. ***Flammability limits at 1 atm and 25°C as defined by M.G. Zabetakis, US Bureau of Mines Bulletin 627.	
1) Note: If the required fuel temperature is above ambient air temperature, adequate thermal insulation and heat tracing of fuel lines and fuel control system is required to avoid condensation. If condensates form during shutdown or are otherwise introduced, provisions should be made to drain fuel lines just before start up to ensure that gas fuel condensation is completely eliminated.	

8.1.1 GASEOUS FUEL SUITABILITY - A fuel composition should be provided to determine the gas fuel suitability for Solar products. In addition, any entrained solid contaminants should be identified, along with their concentrations and size. For gaseous fuels, if water is known to be present, even in minute quantities, the concentration of salts dissolved in this water must be included when calculating the total amount of contaminants. It is also required that a gas analysis including all heavy hydrocarbons beyond C₆ be provided during the proposal stage of the project.

8.1.2 HYDROGEN IN PIPELINE NATURAL GAS – The concentration of hydrogen up to 20% by volume in pipeline natural gas is generally acceptable for SoLoNOx Combustion Systems. Higher concentrations of hydrogen are acceptable for Conventional Combustion Systems. Contact Solar Engineering for evaluation of your specific application.

8.1.3 COKE OVEN GAS – Coke Oven Gas (COG) is the gas released in the process that converts coal into coke. COG is a medium heating value fuel containing mainly hydrogen, methane, water, oxygen, carbon monoxide, nitrogen and carbon dioxide. However, COG also has extreme levels of harmful contaminants including:

- Tar
- Light oil vapors (aromatics), mainly Benzene, Toluene and Xylene (BTX)
- Naphthalene vapor
- Ammonia gas
- Hydrogen sulfide gas
- Hydrogen cyanide gas
- Calcium carbonate from direct water cooling of COG
- Trace metals

The contaminants found in COG must be controlled to levels listed in Tables 1 and 6. Contact Solar for recommendations on Balance of Plant equipment to remove or reduce the contaminants to levels acceptable for gas turbine operation. The superheat level specified in Table 6 is also required for COG to ensure remaining naphthalene and heavy hydrocarbons do not precipitate out in the fuel system.

8.1.4 GASEOUS FUEL SUPPLY PRESSURE - Fuel supply pressure should be maintained at constant level to minimize wear damage to the fuel control system caused by fluctuating and unstable fuel pressures.

8.1.5 GASEOUS FUEL USED FOR PNEUMATIC START SYSTEMS - When gaseous fuel is used to supply the turbine pneumatic start system, it must meet the same quality requirements shown in Table 6.

8.2 DISTILLATE FUELS - Distillate fuel shall be a homogeneous mixture of hydrocarbon compounds. The fuel, when received, shall be clear, bright, and free of any haze, as viewed in ordinary light through a clear vessel. Technical requirements shall be as specified in Tables 7 and 8.

Table 7. Distillate Fuels - Physical and Chemical Requirements (see Note 2)

Physical and Chemical Descriptions	ES9-98 Limits	Test Methods
Sulfur	See Table 1	D2622, D4294, D5453 or D7220.
Aromatics	35% by volume maximum.	ASTM D1319 and D6591 (see Note 1)
Carbon residue on 10% distillation residue	≤ 0.35%.	ASTM D524
Cloud point	At least 10°F (6°C) below expected minimum ambient temperature.	ASTM D2500
Copper strip corrosion	No 3 (3hr at 122°F (50°C)).	ASTM D130
Distillation	90% distillation temperature from 540°F (282°C) to 640°F (338°C). End point at 690°F (366°C) maximum.	ASTM D86
Flash point	> 100°F (38°C) or > legal limit.	ASTM D93
Fuel Bound Nitrogen	Measurement required for liquid emissions guarantees	ASTM D4629 or D5762
LHV	>18,000 Btu/lb, >41838 kJ/kg.	ASTM D240
Lubricity, HFRR @ 60°C	520 micron maximum.	ASTM D6079
Olefins and Diolefins	5% by volume maximum.	ASTM D1319
Pour point	At least 10°F (6°C) below cloud point.	ASTM D97
Reid vapor pressure	< 3 psia, < 20.6 kPa	ASTM D323
Specific Gravity	0.775 - 0.875	ASTM D1298
Viscosity, Kinematic	1 - 12 centistokes at 100°F (38°C)	ASTM D445

Notes:

- 1) Use ASTM D5186 for fuels having final boiling points over 600°F.
- 2) These fuel properties are established at the refinery. If the project fuel exceeds these limits, it will not be treatable through centrifuge or filtration at site. If any property deviates from these limits, approval from Solar is required.

Table 8. Distillate Fuels - Contaminant Limits (see Notes 1 & 2)

Description of Contaminants	ES9-98 Limits	Test Methods
Ash (see Note 2)	≤ 0.01 % maximum.	ASTM D482
Liquid, Water	≤ 0.25 cc free water per liter at an ambient temp of 80°F (27°C)	ASTM D6304
Sodium & Potassium	See Table 1.	ASTM D3605 or D7111
Solids	≤2.6 mg/liter of sediment, solid or hard contaminants, 90% of the 2.6 mg shall be less than 5 micron in size. Max allowable size ≤ 10 micron	ASTM D6217
Calcium & Magnesium	See Table 1.	D3605, D511 or D7111
Chlorine	See Table 1.	ASTM D512
Fluorine	See Table 1.	ASTM D1179
Lead	See Table 1.	ASTM D3605, D3559 or D7111
Vanadium (see Note 2)	See Table 1.	ASTM D3605, D3373 or D7111
Others – Aluminum + Silicon, Antimony, Arsenic, Bismuth, Boron, Cadmium, Gallium, Indium, Mercury and Phosphorous	See Table 1.	ASTM D7111

Notes:

- 1) If the project fuel exceeds these contaminant limits, fuel must be treated to achieve full contaminant quality compliance.
- 2) Non-compliant fuel-bound organometallic contaminants are not treatable by centrifuge
 - a. **Multiple Fuel Sources** - If more than one fuel source is available, individual fuel analyses of all fuel sources must be submitted to review to ensure proper fuel handling.

8.2.1 BIODIESEL - Biodiesel is a fuel that is typically made from various sources including vegetable oils, animal fat and used cooking oils. The oils or animal fats are chemically processed to form a fatty acid methyl ester (FAME). Raw oils from vegetables, animal fats and/or waste cooking oils are not considered to be a biodiesel fuel. The biodiesel is typically blended with the diesel fuel and the fuel blend should not exceed 20 percent (%) by volume and this is referred as B20 biodiesel fuel. Any biodiesel blend above B20 must be reviewed by Solar. The fuel quality must meet the requirements listed in Table 7, 8 and 9.

Table 9. Biodiesel Fuels - Physical and Chemical Requirements

Biodiesel (B20) Properties	Test Method	Limits
Biodiesel/Fatty Acid methyl Ester (FAME)	ASTM D7371	20% by volume maximum
Methanol	EN 14110	0.05% wt maximum
Oxidation Stability	EN 14112	6 hours minimum
Acid Number	ASTM D664	0.3 KOH/g maximum
Monoglyceride	ASTM D6584	0.1% wt maximum
Diglyceride	ASTM D6584	0.05% wt maximum
Triglyceride	ASTM D6584	0.05% wt maximum
Free Glycerin	ASTM D6584	0.005 % wt maximum
Total Glycerin	ASTM D6584	0.05% wt maximum

8.2.2 DISTILLATE FUEL SUPPLY TEMPERATURE - Distillate fuel supply temperature at turbine package fuel inlet shall be no lower than the temperature at which the viscosity is 12 centistokes or cloud point temperature plus 10°F, whichever is higher. The fuel supply temperature shall not be lower than -65°F, nor higher than +140°F.

8.2.3 DISTILLATE FUELS – The Solar Fuel Suitability Inquiry Form in Appendix D must be completed.

8.3 NATURAL GAS LIQUID FUELS - Natural gas liquid fuels shall consist primarily of saturated paraffinic hydrocarbons such as ethane, propane, butane, pentane, hexane and heptane either individually or mixtures of some or all of the above. Technical requirements shall be as specified in Table 10.

Table 10. Natural Gas Liquid Fuels - Physical and Chemical Requirements

Property	Allowable Limits	Test Method
Composition percent by volume	Report	ASTM D2163
Vapor pressure at 100°F (38°C)	780 psia maximum	ASTM D1267 or ASTM D2598
Relative density at 60°F/60°F (15°C/15°C)	0.37 to 0.68	ASTM D1657 or ASTM D1298
Copper strip	No. 1 minimum	ASTM D1838
Moisture content for fuels with relative density 0.37 to 0.51	Pass	Use one of the methods for moisture content as described in the Commercial Propane Dryness Test, Cobalt Bromide Method or Dew Point Method of the Natural Gas Processors Association Publication 2140
Free water content for fuels with relative density of 0.51 to 0.68	None	ASTM D1657 - The presence or absence of water shall be determined by inspection of the sample on which the relative density is determined
Solid contaminants	Less than 2.6 mg of sediment per liter of fuel. 90% of sediment shall be less than 5 microns in size. Maximum size of any solid sediment particle shall be less than 10 microns.	ASTM D6217
Lower Heating Value	18,000 Btu/lb. Minimum	ASTM D240

8.3.1 NATURAL GAS LIQUID SUPPLY TEMPERATURE - Liquid gas supply temperature at the fuel inlet to the package shall be between -65°F and +90°F and shall be in a liquid phase only.

8.3.2 NATURAL GAS LIQUID FUELS - The following information is required to determine the suitability of natural gas liquids:

- Composition on volumetric gases
- Vapor pressure at 100°F
- Relative density at 60°F
- Viscosity at 100°F

8.4 MULTIPLE FUEL SOURCES - If more than one fuel source is available, individual fuel analyses of all fuel sources must be submitted to review to ensure proper fuel handling.

8.5 CONCENTRATION OF FUEL BORNE CONTAMINANTS - Fuel borne contaminants constitute only one of several means by which contaminants enter the turbine engine. The minimum fuel quality allowed depends on the quality of the other fluids, such as air, injected water and water carryover (if applicable). In order to assess the impact of fuel borne contaminants on the total concentration present in the engine, the fuel equivalent concentration (FEC) of each fuel borne contaminant can be calculated using the following function.

$$\text{Concentration in fuel, ppmw FEC} = \frac{18380}{\text{LHV}} \times (1-K) \times F$$

Where: LHV = lower heating value, Btu/lb

- K = fuel cleanup (if applicable), expressed as value <1.0
- F = concentration in fuel entering combustor, ppmw

8.5.1 CONCENTRATION GUIDELINES FOR FUEL BORNE CONTAMINANTS - In general, contaminants from fuel are expected to contribute less than 10% of the total concentration allowed. Depending on the fuel of application involved and the potential for system upsets, Table 2 serves as an approximate guideline for fuel borne contaminants, recognizing that variations in fluid quality can significantly change the balance implied in this guideline.

9.0 HANDLING AND STORAGE OF FUELS

9.1 STORAGE AND HANDLING EQUIPMENT – The selection of equipment for storage and handling is a crucial part of ensuring that liquid fuel contaminants generally conform to ES 9-98 when it reaches the engine. Cleanup devices will always be required because contamination frequently occurs during transportation. Solar has identified the types of equipment that are required to ensure that liquid fuel being supplied to an engine will be cleaned up to specification. Product Information Letter PIL 162 outlines recommendations for various liquid fuel applications.

9.2 ADDITIONAL INFORMATION - Refer to PIL 162 and ASTM D4418 for more information on handling and storage of fuels.

10.0 NOTES

10.1 SIGNIFICANCE OF LIMITS - Total contaminants should comply with Table 1. The following subparagraphs explain the significance of limits in the specification.

10.1.1 SULFUR – Sulfur and sulfur compounds can have an impact on the fuel system life and maintenance, turbine hot section life, exhaust system life and a pollutant emissions signature. The presence of sulfur in the combustor will burn or oxidize to form sulfur dioxide. In the presence of even minute quantities of sodium and potassium in the combustor environment (excess oxygen and high thermal load), sodium and potassium sulfates are readily formed. These salts if condensed onto turbine airfoil surfaces will react with the base metal, resulting in hot corrosion degradation. Gas turbines with waste heat recovery equipment must operate above the sulfuric acid dewpoint, which may require additional sulfur control to prevent cold end corrosion. Additionally, US Federal and certain local air pollution regulations require more restrictive limits on sulfur. Fuel bound sulfur in diesel fuel has been found to promote carbon deposition on hot surfaces of lean premix SoLoNOx® injectors leading to the build-up of deposits in the premix duct that left unchecked can result in injector or even engine damage. As a result, the sulfur content is being limited for SoLoNOx liquid fuel operation for applications based on a complete analysis of the diesel fuel by Solar Engineering.

10.1.1.1 HYDROGEN SULFIDE - Hydrogen sulfide can occur both in natural gas, processed and manufactured gases. It is corrosive to some materials such as bronze and brass used in fuel gas systems, the corrosiveness being more severe in the presence of water and at high pressure. If the sulfur exceeds the limit then the fuel system materials must be upgraded. Hydrogen sulfide burns to sulfur dioxide and sulfur trioxide, which results in the corrosion described above. Some manufactured gases also contain organic sulfur compounds, which are corrosive to some control system materials. Since hydrogen sulfide is toxic, if it is present in the gas, precautions must be taken to detect leaks.

10.1.1.2 ELEMENTAL SULFUR DEPOSITION - Aside from H₂S, natural gas may contain other sulfur compounds or sulfur vapor that even in very low concentrations (ppbw) can form solid elemental sulfur. In sufficient quantities, elemental sulfur can impede operation of fuel valves and gas flow measurement devices on the gas turbine package. ASTM D7800 provides a test method to determine if elemental sulfur is contained in a gas fuel. If deposition takes place, the solution is to heat the gas fuel prior to the skid edge. The temperature that the gas must be heated to will depend on the concentration of the sulfur in the gas supply. For standard pipeline gas with low concentrations of total sulfur, fuel heating in the range of 130°F to 160°F (55°C to 70°C) has proven effective at preventing sulfur deposition.

10.1.2 SODIUM AND POTASSIUM - Sodium and potassium can combine with vanadium to form eutectic, which melts at temperatures as low as 1050°F (566°C) and can combine with sulfur in the fuel to yield sulfates with melting points in the operating range of the gas turbine. These compounds produce severe corrosion in the turbine hot section. Accordingly, the sodium plus potassium level must be limited, but each element must be measured separately. These elements can be removed by water washing and subsequent removal with a centrifuge or electrostatic precipitator.

10.1.3 VANADIUM - Vanadium can form low melting compounds such as vanadium pentoxide which melts at 1275°F (691°C), and alkali metal vanadates which melt as low as 1050°F (566°C) which can cause severe corrosive attack on all of the high temperature alloys in the gas turbine hot section.

10.1.4 MERCURY - Mercury compounds are corrosive to aluminum, copper, lead, and silver; therefore, these materials are to be avoided if mercury is present. Mercury compounds are not known to be corrosive to the hot section of a gas turbine. Mercury in the exhaust of the turbine must be limited to comply with local regulations.

10.1.5 LEAD - Lead can cause corrosion and in addition, it can spoil the beneficial effect of magnesium additives on vanadium corrosion. Since lead is rarely found in significant quantities in crude oils, its appearance in fuel oils is primarily the result of contamination during processing or transportation.

10.1.6 FLUORINE AND CHLORINE - Halides such as fluorine and chlorine as well as alkali/mixed halides and alkali sulfates can attack the protective oxide scale on hot turbine components, thus accelerating the rate of oxidation.

10.1.7 CALCIUM AND MAGNESIUM - Calcium and magnesium are not harmful from a corrosion standpoint; in fact, it serves to inhibit the corrosive action of vanadium. However, calcium can produce hard bonded deposits that are not self-spalling when the gas turbine is shut down. These hard bonded deposits are not readily removed by water washing of the turbine (Ref. ES 9-62). The fuel washing systems used to reduce the sodium and potassium levels will also reduce calcium levels.

10.1.8 OTHER TRACE METALS - Oxides of other trace metals with or without other impurities can be deposited on blades and vanes forming extremely hard and difficult-to-remove deposits. The presence of these oxides will also increase the rate of oxidation of blade and vane alloys at high temperatures.

The limits for aluminum and silicon are equal to 0.5 ppmw FEC, which is same as that of other trace metals. The source of aluminum and silicon is typically found to be aluminum silicates catalyst used in the catalytic cracking process that may end up in the fuel. The amount of aluminum and silicon in the fuel should be reduced to acceptable levels. These contaminants could cause abrasive wear of various engine parts. These can be reduced by centrifuge.

10.1.9 PARTICULATES IN AIR - Inert particulates in the turbine inlet air cause erosion and/or fouling of the compressor section. By limiting the size of the particulates, erosion is minimized. Contamination of the compressor blading is caused by smaller particulates. Factors such as humidity, presence of oil or soot and dust particle composition affects the rate of fouling.

10.1.10 SOLIDS IN WATER - Inert solid particles in water can cause wear and plugging of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section would be the result.

10.1.11 pH OF WATER - The pH of water is limited from slightly acidic to slightly basic. Strong bases or acids would attack various components in the water control and injection system.

10.1.12 FUEL GAS VOLUME RATIO - The fuel gas volume ratio is an indication of the capability of the fuel control to properly schedule the fuel flow. If this ratio is within the specified limits, the standard system without modifications can be used. Ratios with values up to 2 can be handled with minor modifications to the fuel injection system. If the ratio is between 2 and 4, the modifications are substantial and if the ratio is above 4, a redesign of the combustor is required.

10.1.13 FUEL GAS MASS RATIO - The fuel gas mass ratio is an indication of the effects of the fuel mass flow on the performance and matching of the turbine. Ratios up to 5 are acceptable without modification. If the ratio is between 5 and 10 then a fuel meeting the standard requirements must be used for start and acceleration to avoid compressor surge. If the ratio is above 10, extensive turbine redesign is required to accommodate larger turbine mass flow.

10.1.14 HYDROGEN AND CARBON MONOXIDE IN GAS - The presence of hydrogen and/or carbon monoxide in the fuel gas above the specified levels can cause safety and materials problems and the requirements in these tables may apply. For low concentrations of hydrogen mixed with pipeline quality natural gas (20% or less) exceptions to these requirements are often available with approval by Solar engineering.

Table 11. Requirements for Hydrogen in Gaseous Fuels

H ₂ LEVEL	REQUIREMENTS
H ₂ > 4%	i) Review of fuel system materials for hydrogen embrittlement ii) Special safety precautions may be required such as detectors in the package, separation of the engine and generator compartments, and leak free piping joints iii) Special sequenced start & purge system required
H ₂ > 9%	i) Starts and accelerations may be required on a standard fuel with transfer to the high H₂ fuel at idle power or greater ii) Fuel system purge of the high H₂ fuel may be required following each shutdown iii) Control system fuel control software may need modifications

Table 12. Requirements for Carbon Monoxide in Gaseous Fuels

CO LEVEL	REQUIREMENTS
CO > 0%	Since CO is toxic, precautions must be taken to detect leaks.
CO > 12.5%	i) Special safety precautions must be taken such as detectors in the package, separation of the engine and generator compartments, and leak free piping joints ii) Special sequenced start & purge system required
CO > 18%	Starts and accelerations must be made on a standard fuel with transfer to CO rich fuel at idle or above

10.1.15 FLAMMABILITY - The ratio of the upper-to-lower flammability limits is an indication of whether the gas will allow engine starting and adequate range of operation, in particular on single shaft generator sets.

10.1.16 FLAME TEMPERATURE - The adiabatic flame temperature of gas fuels is used to determine its suitability. If the value is below the limit, major combustion system modifications and/or changes to operating procedures may be required.

10.1.17 SILOXANES – The presence of siloxanes in fuel gas is known to result in silicon-based deposition in the gas turbine flow path that can cause damage, high rates of performance

degradation, and higher overhaul costs. The rate of deposition is a function of the type and quantity of silicon-based material contained in the fuel, and is thus produced from the combustion process. As such damage and performance loss is preventable only by control of siloxane levels in the fuel, such damage is not covered by Solar's warranty. It is, therefore, the customer's responsibility to monitor and minimize as appropriate siloxane content through the use of a reliable siloxane removal system.

Based on engine operating experience to date, Solar considers that limiting the amount of silicon, as measured by the Jet-Care SiTest method, to no more than 5 mg Si/Nm³ CH₄ for the Mercury 50™ and 10 mg Si/Nm³ CH₄ for all other turbines should result in target time between overhaul with normal performance degradation.

10.1.18 PARTICULATES IN GAS - Solid particles in gas can cause wear and plugging of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section would be the result.

10.1.19 FUEL SUPPLY TEMPERATURE - For gas fuels, there are four considerations. The most restrictive of the requirements shall apply. 1) The fuel must be supplied at the inlet flange to the package to ensure that no liquids can enter the fuel control and injection system. Liquids in a gas system cause malfunction and serious thermal damage to the engine if liquid is injected with the gas into the engine. 2) The thermal capability of the materials in the fuel delivery system must not be exceeded. 3) The fuel must be supplied at the inlet flange to the package to ensure elemental sulfur de-sublimation does not occur for installations where elemental sulfur is present. 4) The fuel must be supplied at the inlet flange to the package to ensure combustion stability. High performance, high pressure ratio combustion systems as used on the Titan 250 SoLoNOx configuration can be sensitive to changes in fuel density.

For distillate fuels, the temperature must be above the cloud point to prevent plugging of the filters and control components. It must also be above the temperature that corresponds to a viscosity of 12 centistokes to ensure satisfactory atomization required for starting performance. The range of allowable temperatures is determined by the thermal capabilities of the materials in the control system.

For natural gas liquid fuels, the allowable temperature range is determined by the control system materials and the critical point of the lightest fuel. This latter constraint is to limit the vapor pressure on the fuel.

10.1.20 VISCOSITY - Viscosity of a fluid is a measure of its resistance to flow. In distillate fuel it is highly significant since it indicates both the relative ease with which the fuel will flow or may be pumped and a measure of atomization by the fuel injectors. Minimum viscosity is limited because standard fuel pumps will not perform satisfactorily if viscosity reaches too low a value. Maximum viscosity is limited since too high a viscosity can cause excessive pressure losses in the piping system and poor fuel atomization.

10.1.21 RELATIVE DENSITY OF DISTILLATE - Relative density alone is of no significance as an indication of the burning characteristics of fuel oil. However, when used in conjunction with other properties, it is of value in weight-volume relationships and in calculating the heating value of the fuel.

10.1.22 REID VAPOR PRESSURE - The Reid vapor pressure is a criterion of freedom from foaming and fuel slugging due to vaporization of the fuel. Special fuel systems are required if the Reid vapor pressure is above the specified level.

10.1.23 CLOUD AND POUR POINTS - Cloud point is the temperature at which a cloud or haze of wax crystals appears. Operation at temperatures below the cloud point causes plugging of filters. Pour point is an indication of the lowest temperature at which a fuel can be stored and still be capable of flowing under gravitational forces. The cloud and pour points are prescribed in accordance with the conditions of storage and use. Heated tanks and lines may be required where ambient temperature is below the cloud and pour points of the proposed fuels.

10.1.24 FLASH POINT - Flash point is an indication of the maximum temperature at which a fuel can be stored and handled without serious fire hazard. The minimum permissible flash point is usually regulated by Federal, State, or Municipal laws and is based on accepted practices in handling and use.

10.1.25 DISTILLATION - The distillation test indicates the volatility of a fuel and the ease with which it can be vaporized and burned. It also indicates the possibility of carbon deposition and smoke formation.

10.1.26 AROMATICS AND OLEFINS - Combustion of highly aromatic fuels can result in increased smoke. Carbon or soot deposition and increased combustor metal temperature resulting in exhaust particulate emissions, opacity violations, and reduced engine life. Use of fuels with excessive olefin content can result in decomposition of the fuel, which causes plugging of fuel system components including the fuel injectors.

10.1.27 LOWER HEATING VALUE (LHV) - The lower heating value is used to calculate actual fuel consumption. Also, if the value for distillate fuels is below the limit, it is an indication of a heavy fuel, which may have other properties exceed in the limits.

10.1.28 CARBON RESIDUE - Carbon residue is a measure of the carbonaceous material left in a fuel after all the volatile components are vaporized in the absence of air. It is a rough approximation of the tendency of a fuel to form carbon deposits in the combustion system of the gas turbine.

10.1.29 ASH - Ash is the noncombustible material in a fuel. Ash-forming materials may be present in fuel in two forms: (1) solid inert particles and (2) oil or water-soluble metallic compounds. The solid particles are for the most part the same material that is designated as sediment in the water and sediment test. Depending on their size, these particles contribute to wear in the fuel system and to plugging of fuel filter and fuel injectors. The soluble metallic compounds have little or no effect on wear or plugging, but may contain elements that produce hot section corrosion and deposits as described above.

10.1.30 COPPER STRIP CORROSION - This test provides an indication of possible corrosive attack of non-ferrous metals such as copper, brass, and bronze.

10.1.31 WATER AND SEDIMENT IN DISTILLATES - Appreciable amounts of water and sediment in fuel tend to cause fouling of the fuel-handling facilities and to give trouble in the fuel system of the turbine. An accumulation of sediment in storage tanks and on filter screens may obstruct the flow of fuel from the tank to the package. Water in distillate fuels may cause corrosion of tanks and equipment. Water in the fuel also provides a place for microbiological growths to occur. These growths can plug filters and screens and can promote corrosion of fuel tanks.

10.1.32 COMBUSTIBLES IN AIR - If combustibles are ingested into the engine inlet, the hydrocarbon and carbon monoxide levels in the exhaust will be increased assuming none of the combustibles complete combustion.

10.1.33 FUEL BOUND NITROGEN - Fuel Bound Nitrogen (FBN) found in distillate fuels causes NOx in the exhaust to increase. In order to offer liquid emissions guarantee, FBN must be determined by fuel analysis.

10.1.34 LUBRICITY - Low sulfur diesels tend to have a reduced lubricity and that could affect the life and reliability of the fuel pumps. The processes used to remove the sulfur from fuel also remove the natural occurring lubricity compounds in the fuel. Special fuel pumps are required when fuels do not meet the requirement listed in Table 7.

10.1.35 BIODIESEL/FATTY ACID METHYL ESTER (FAME) – Biodiesel fuels are produced from vegetable oil, animal oil/fats and waste cooking oil. Any biodiesel blend above B20 (20% by volume of biodiesel blended with diesel fuel) must be reviewed by Solar.

10.1.36 OXIDATION STABILITY – It is important that the biodiesel blend properties do not change over time during the recommended period of storage and usage. Oxidation Stability is a measure of fuel storability and its deposits formation propensity. The biodiesel fuels contain esters chemical group (contains two oxygen atoms) and unsaturated (double bonds) compounds that can vary based on the feedstock. Due to the esters chemical group and the unsaturation, the oxidation stability of biodiesel fuels is typically lower than that of the diesel fuel. Oxidation of fuel can cause deposits in storage tank, fuel system and fuel injectors and can cause filter clogging.

10.1.37 ACID NUMBER – The acid number is an indicator of the concentration of acids (such as free fatty acids or processing acids) present in the biodiesel or fuel oil when produced, and acids that are formed upon aging. Biodiesel blends with an acid number exceeding the specification have been shown to increase fuel system deposits and can increase the likelihood for corrosion.

10.1.38 GLYCERIN AND GLYCERIDES – Free glycerin and bonded glycerin (mono-, di- and tri-glycerides) are contaminants in biodiesel fuels that get into the fuel during the manufacturing process. Total glycerin is the sum of free glycerin and glycerin portion in glycerides. Free glycerin is a major byproduct of biodiesel production, which is removed during the fuel cleanup. High contents of total glycerin may adversely affect the cold weather properties of the fuel and can cause injector deposits and filter plugging.

10.1.39 METHANOL – Methanol/alcohol is a contaminant which gets into biodiesel during the manufacturing process. Methanol content is analyzed in conjunction with the flash point to meet the safety requirements.

APPENDIX A

TOTAL SITE CONTAMINATION WORKSHEET FORM 3091

(Blank form and Sample Calculation)

TOTAL SITE CONTAMINATION WORKSHEET		INQUIRY NO.	Q.R. NO./S.O. NO.
CUSTOMER		DATE ISSUED	DATE REQUIRED
ENGINE MODEL	FUEL	FREQUENCY OF STARTS	RUNNING TIME PER START
EQUIPMENT LOCATION	LOAD CONDITIONS ☐ HIGH ☐ LOW ☐ STEADY ☐ CYCLIC		
ALTITUDE FEET	AMBIENT TEMPERATURE RANGE °F MAXIMUM; °F MINIMUM		AVERAGE HUMIDITY %
INSTRUCTIONS - Enter best known values. Explanations and helpful information are provided on the reverse side. Perform calculations as indicated to obtain total site contamination for each (or all) species of interest.			

EVAPORATIVE COOLER ☐ YES ☐ NO WATER INJECTION ☐ YES ☐ NO

		Concentrations, ppmw	Na + K	S	F	V	Pb	Ca + Mg
	1	Ambient Air, ppmw						
	2	Fuel, ppmw						
	3	Injected Water, ppmw						
	4	Evaporative cooling water, ppmw						
	5	LHV, Btu/lb						
	6	Compute: $18,380/[5]$						
Air	7	Air-to-Fuel Ratio						
	8	1 - N (Correction Factor)						
	9	Compute: $[1] \times [6] \times [7] \times [8]$, ppmw FEC						
Fuel	10	1 - K (Fuel Factor)						
	11	Compute: $[2] \times [6] \times [10]$, ppmw FEC						
Water	12	Water-to-fuel Ratio						
	13	Compute: $[3] \times [6] \times [12]$, ppmw FEC						
Evaporative Cooling	14	E.C. Carryover Rate, GPM						
	15	Fuel Flow rate, million Btu/hr						
	16	Compute: $\frac{[4] \times [5] \times [6] \times [14] \times 5 \times 10^{-4}}{[15]}$ ppmw FEC						
	17	Total Contaminants, ppmw FEC $[9] + [11] + [13] + [16]$						
	18	Max. Allowable Limits, ppmw FEC per ES 9-98	0.5	10,000	1	0.5	1	2

COMMENTS:

PREPARED BY: _____ DATE: _____

Row #	Term Explanation	Typical Values		
1	Concentration of contaminant in ambient air, expressed as ppmw in air	Unless available for site of interest, select most appropriate value for S and Na+K from ranges given below. All other contaminants are assumed to be zero unless specifically known to be present.		
		<u>S(ppmw)</u>		<u>Na+K(ppmw)</u>
		.0.001	Moderately clean	>0.001 Arctic
		0.050-0.007	City	>0.010 Agricultural/Residential
		.0.100	Industrial	0.003-0.010 Industrial
		>0.100	Processing/Chemical Plant	0.007-0.260 Coastal (less than 1 mile)
				0.010-0.136 Desert
				0.010-3.600 Offshore platform
2	Concentration of contaminant in fuel supply expressed as ppmw in fuel	For gas fuels, and residual liquid water from processing can be very high in dissolved salts. If possible, analyses of trace water present in gas fuel is the best method for obtaining reliable data. For liquid fuels, direct measurement for contaminants is recommended. Some APPROXIMATE values for S and Na+K are provided here:		
		<u>S(ppmw)</u>	<u>Na+K(ppmw)</u>	
		1,000	.0.1	pipeline gas
		>10,000	>3.0	process gas
		>10,000	>3.0	biomass gas
		>10,000	>1.0	distillate liquid fuel
3	Concentration of contaminant in injected water, expressed as ppmw in water	Contaminants in treated water at entry into combustor should be known, either based on actual water analyses or equipment specifications (auto shut down limit).		
4	Concentration of contaminant in water delivered to header of evaporative cooler, expressed as ppmw	Contaminants in reservoir (for recirculating systems) or feedwater (for non-recirculating systems) should be known, either based on actual water analyses or equipment specifications.		
5	Lower heating value, expressed as 10 ⁶ But/hr	Available from fuel analysis report.		
6	FUEL LHV ADJUSTMENT FACTOR USING 18,380 BTU/# AS REFERENCE FUEL PER ES 9-98.			
7	Air-to-fuel ratio	Use actual value -generated by FASTE run at site-specific conditions with project fuel. Otherwise:	Multiply by	<u>LHV Btu/pound</u> 20,000
		60.04 for Mars 100		
		60.05 64.08 for Mars 90		
		71.58 for Centaur 40		
		58.07 for Centaur 50		
		62.94 for Saturn 20		
		60.61 for Mercury 50		
		57.21 for Taurus 60		
		57.21 for Taurus 70		
		57.74 for Titan 130		
		59.06 for Titan 250		
8	Correction factor for air cleanup system, N	Use N = 0.99		
9	CONTAMINANTS FOUND IN AIR ENTERING ENGINE, [1] x [6] x [7] x [8], PPMW, FUEL EQUIVALENT CONCENTRATION			
10	Fuel factor to account for fuel cleanup system, K	Use K = 0.95 unless instructed otherwise. If no fuel treatment is applicable between supply and engine, use 0 here.		
11	CONTAMINANTS FOUND IN FUEL ENTERING ENGINE, [2] x [6] x [10], PPMW, FUEL EQUIVALENT CONCENTRATION			
12	Water-to-fuel ratio	Use actual value. Range is typically from 0.5 to 1.0.		
13	CONTAMINANTS FOUND IN INJECTED WATER, [3] X [6] X [12], PPMW, FUEL EQUIVALENT CONCENTRATION			

Row #	Term Explanation	Typical Values
14	Rate of liquid water carried off the evaporation cooler (carryover) into air steam, expressed as gallons per minute	It is expected that during the duty cycle of the engine, liquid water can accidentally enter the air steam. Use the following values unless otherwise instructed by Package Engineering. 0.1 GPM for Titan 250 0.1 GPM for Titan 130 0.1 GPM for Taurus 70 0.1 GPM for Taurus 65 0.1 GPM for Taurus 60 0.1 GPM for Centaur 40 0.1 GPM for Centaur 50 0.1 GPM for Mercury 50 0.1 GPM for Saturn 20
	Adjustment factor for mist eliminator if applicable, E	Mist eliminators are required for evaporative cooler installations. Use the following values unless otherwise instructed. No mist eliminator: evaporative cooler cannot be used Mist eliminator efficiency: 99.9% on 50 micron water droplets (Confirm with evaporative cooler manufacturer that mist eliminator drop limit size is 50 micron or smaller.)
15	Fuel flow rate expressed in million Btu per hour	Conversion from million Btu/hour to pounds per sec of fuel flow is included in the expression in the final expression in [16].
16	CONTAMINANT FOUND IN WATER CARRYOVER FROM EVAPORATIVE COOLER, IF USED $\frac{[4] \times [5] \times [6] \times [14] \times [15] \times 5 \times 10^{-4}}{[15]}$	PPMW, FUEL EQUIVALENT CONCENTRATION.
17	TOTAL CONTAMINANT FROM ALL SOURCES, [9] + [11] + [13] + [16], PPMW, FUEL EQUIVALENT CONCENTRATION.	
18	MAXIMUM ALLOWABLE LIMITS FOR EACH CONTAMINANT PER ES 9-98, PPMW, FUEL EQUIVALENT CONCENTRATION	

TOTAL SITE CONTAMINATION WORKSHEET		INQUIRY NO.	Q.R. NO./S.O. NO.
CUSTOMER EXAMPLE		DATE ISSUED	DATE REQUIRED
ENGINE MODEL CENTAUR T4000	FUEL Diesel	FREQUENCY OF STARTS Monthly	RUNNING TIME PER START 500 hours
EQUIPMENT LOCATION San Diego, California	LOAD CONDITIONS ☐ HIGH ☐ LOW ☐ STEADY ☐ CYCLIC		
ALTITUDE 100 FEET	AMBIENT TEMPERATURE RANGE 90°F MAXIMUM; 40°F MINIMUM		AVERAGE HUMIDITY 50% RH
INSTRUCTIONS - Enter best known values. Explanations and helpful information are provided on the reverse side. Perform calculations as indicated to obtain total site contamination for each (or all) species of interest.			

EVAPORATIVE COOLER ☐ NO

WATER INJECTION ☐ YES ☐ NO

	Concentrations, ppmw	Na + K	S	V	Pb	F	Ca + Mg
1	Ambient Air, ppmw	0.03	20	0	0	0	0
2	Fuel, ppmw	0.1	500	0.05	0	0	0
3	Injected Water, ppmw	0.2	0.1	0	0	0	0
4	Evaporative cooling water, ppmw	10	100	0	0	0	0
5	LHV, Btu/lb	20,100					
6	Compute: 18,380/[5]	0.914					
Air	7	Air-to-Fuel Ratio					
	8	1 - N (Correction Factor)					
	9	Compute: [1] x [6] x [7] x [8], ppmw FEC					
Fuel	10	1 - K (Fuel Factor)					
	11	Compute: [2] x [6] x [10], ppmw FEC					
Water	12	Water-to-fuel Ratio					
	13	Compute: [3] x [6] x [12], ppmw FEC					
Evaporative Cooling	14	E.C. Carryover Rate, GPM					
	15	Fuel Flow rate, million Btu/hr					
	16	Compute: $\frac{[4] \times [5] \times [6] \times [14] \times 5 \times 10^{-4}}{[15]}$ ppmw FEC					
	17	Total Contaminants, ppmw FEC [9] + [11] + [13] + [16]					
	18	Max. Allowable Limits, ppmw FEC, per ES 9-98					

COMMENTS

PREPARED BY: _____ DATE: _____

APPENDIX B

DERIVATION OF TOTAL FUEL EQUIVALENT CONCENTRATION EQUATION FOR UNDESIRABLE CONTAMINANTS

The expression given in paragraph 3.1.3 for directly fired applications is derived from first principles in section 1. Section 2 explains the incorporation of system efficiencies into this fundamental expression and its use in the Total Site Contamination Worksheet, Form, 3091, with the appropriate unit conversions.

B1.0 Derivation of Fundamental Expression for Total Fuel Equivalent Concentration (For Directly Fired Applications Only)

Solar's air, fuel, and water specification is based on FUEL EQUIVALENT CONCENTRATIONS, i.e., the concentration of a given contaminant as if that given contaminant were present in the fuel alone, with the fuel having a LHV of 18,380 Btu/lb or 10,212 kcal/kg.

Nomenclature used in the derivation is given in Table B-1.

Table B1. Nomenclature for Fuel Equivalent Derivation

Input Steam to Gas Turbine	Mass Flow Rate	Concentration of i^{th} Contaminant	Mass Flow Ratios of Each Steam or Fuel
Reference Fuel	r	R_i	1
Fuel	f	F_i	1
Air	a	A_i	a/f or (AFR)
Water	w	W_i	w/f or (WFR)
Steam	s	S_i	s/f or (SFR)
Carryover	c	C_i	c/f or (CFR)

(LHV) = lower heating of a given fuel, Btu/lb

i = Na, K, V, Pb, etc.

T_i = Fuel equivalent for the reference fuel which has a lower heating value of 18,380 Btu/lb (10,212 kcal/kg)

The mass flow of the i^{th} contaminant in the combustion products burning the reference fuel is:

$$rR_i + aA_i + wW_i + sS_i + cC_i \quad (1)$$

The total mass flow of the combustion product is:

$$r + a + w + s + c \quad (2)$$

The concentration of the i^{th} contaminant in the combustion products is:

$$\frac{rR_i + aA_i + wW_i + sS_i + cC_i}{r + a + w + s + c} \quad (3)$$

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Next suppose that the total mass flow of the i^{th} contaminant in the combustion products came from the reference fuel alone. Let T_i equal the reference fuel equivalent concentration of the i^{th} contaminant. Then, the concentration of the i^{th} contaminant in the combustion products, the environment of the hot section components, would be:

$$\frac{rT_i}{r + a + w + s + c} \quad (4)$$

Equating Eq. (3) with Eq. (4) and dividing through r gives:

$$T_i = R_i + (a/r) A_i + (w/r) W_i + (s/r) S_i + (c/r) C_i \quad (5)$$

In order to have an expression that gives the Fuel Equivalent, T_i , for the cases where a fuel, f , of any heating value (LHV) are used, Eq. (5) must be modified. It is required that, regardless of the LHV of either fuel, the flow of each fuel be such that the same thermal input is provided to the engine. Therefore,

$$r (18,380 \text{ Btu/lb}) = f (\text{LHV}) \quad (6)$$

or

$$r = \frac{f (\text{LHV})}{18,380 \text{ Btu/lb}}$$

In addition, it is required for the same T_i that the contribution of the contaminant to the total from either fuel r of fuel f be the same.

$$rR_i = fF_i \quad (7)$$

Combining Eq. (6) and Eq. (7) gives:

$$R_i = \frac{18,380}{(\text{LHV})} F_i \quad (8)$$

Substituting Eq. (6) and Eq. (8) into Eq. (5) gives:

$$\begin{aligned} T_i = & \frac{18,380}{(\text{LHV})} F_i + \frac{a}{f(\text{LHV}/18,380)} A_i + \frac{w}{f(\text{LHV}/18,380)} W_i + \frac{s}{f(\text{LHV}/18,380)} S_i \\ & + \frac{c}{f(\text{LHV}/18,380)} C_i \end{aligned} \quad (9)$$

Finally, rearranging and substituting the nomenclature in the fourth column of Table B-1 gives:

$$T_i = \frac{18,380}{(\text{LHV})} [F_i + (\text{AFR})A_i + (\text{WFR})W_i + (\text{SFR})S_i + (\text{CFR})C_i] \quad (10)$$

B2.0 Derivation of Expression Used in Form 3091

Taking Eq. (10) and assigning units to the variables result in the following definition of terms. (The steam term is dropped from the basic expression because it is currently not applicable to *Solar* engines.)

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$$T_i = \frac{18,380}{(\text{LHV})} [F_i + (\text{AFR})A_i + (\text{WFR})W_i + (\text{SFR})S_i + (\text{CFR})C_i]$$

where

- T_i = fuel equivalent concentration of contaminant i, in ppmw
- LHV = lower heating value of fuel, in Btu/lb
- F_i = concentration of contaminant i in fuel entering combustor, in ppmw
- AFR = air-to-fuel mass ratio
- A_i = concentration of contaminant i in air entering compressor, in ppmw
- WFR = water-to-fuel mass ratio
- W_i = concentration of contaminant i in water injected into combustor, in ppmw
- CFR = carryover water-to-fuel mass ratio
- C_i = concentration of contaminant i in carryover water (same as evaporation cooler feedwater), in ppmw

Examining each term in greater detail:

Fuel Term: F_i

Let K = overall efficiency rating for fuel cleanup system

$$\text{Adjusted fuel term} = F_i (1 - K) \quad (11)$$

Air Term: $(\text{AFR})A_i$

A_i is concentration air entering compressor

$$A_i = (1 - N)A_i^{\text{amb}}$$

where N = efficiency of air filter

A_i^{amb} = concentration of contaminant i in ambient air, in ppmw

$$\text{Adjusted air term} = (\text{AFR})(1 - N)A_i^{\text{amb}} \quad (12)$$

Water Term: $(\text{WFR})W_i$

W_i is concentration in water injected into combustor, ALSO THE SET POINT FOR AUTOMATIC SHUTDOWN

Carryover Term: $(\text{CFR})C_i$

Let water carryover rate = $R \text{ gal/min} \times 8.337 \text{ lb/gal}$
 = $8.337 R \text{ lb/min}$

Let fuel flow rate = $f \text{ MBtu/hr}$

$$\frac{f \text{ MBtu}}{\text{hr}} \times \frac{1 \text{ hr}}{60 \text{ min.}} \times \frac{\text{lb}}{\text{LHV Btu}} \times \frac{10^6 \text{ Btu}}{\text{MBtu}} = \frac{16,700f \text{ lb/min}}{\text{LHV}}$$

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Let E = efficiency of mist eliminator

Carryover rate = (8.337R) lb/min

$$\begin{aligned} \text{CFR} &= \frac{8.337R (\text{LHV}) (1 - E)}{16,700f} \\ &= 4.99 \times 10^{-4} R (\text{LHV}) (1 - E)/f \end{aligned} \quad (13)$$

Substitute in Equation (10),

$$\begin{aligned} T_i &= \frac{18,380}{\text{LHV}} [F_i (1 - K) + (\text{AFR}) (1 - N) A_i^{\text{amb}} + (\text{WFR}) W_i \\ &\quad + \frac{4.99 \times 10^{-4} R (\text{LHV}) (1 - E)}{f} C_i] \end{aligned} \quad (14)$$

or

$$\begin{aligned} T_i &= \frac{(18,380)}{\text{LHV}} (1 - K) F_i + \frac{(18,380)}{\text{LHV}} (\text{AFR}) (1 - N) A_i^{\text{amb}} \\ &\quad + \frac{(18,380)}{\text{LHV}} (\text{WFR}) W_i + \frac{(18,380)}{\text{LHV}} (5 \times 10^{-4}) R (\text{LHV}) (1 - E) \frac{C_i}{f} \end{aligned} \quad (15)$$

where $\frac{(18,380)}{\text{LHV}} (1 - K) F_i$ = fuel equivalent concentration of i^{th} contaminant in fuel, ppmw

$\frac{(18,380)}{\text{LHV}} (\text{AFR}) (1 - N) A_i^{\text{amb}}$ = fuel equivalent concentration of i^{th} contaminant in air, ppmw

$\frac{(18,380)}{\text{LHV}} (\text{WFR}) W_i$ = fuel equivalent concentration of i^{th} contaminant in injected water, ppmw

$\frac{(18,380)}{\text{LHV}} (5 \times 10^{-4}) R (\text{LHV}) (1 - E) \frac{C_i}{f}$ = fuel equivalent concentration of i^{th} contaminant in evaporation cooler feedwater, ppmw

T_i = sum of fuel equivalent concentration of i^{th} contaminant from all sources, ppmw

Equation (15) is used in Form 3091.

APPENDIX C

LIQUID FUEL HANDLING AND STORAGE REQUIREMENTS

(MOVED TO PIL 162)

APPENDIX D

LIQUID FUEL SUITABILITY FORM

The table below contains the allowable limits for liquid fuel characteristics and contaminants. Solar's Liquid Fuel System Assessment form should be filled out with the Solar Sales Engineer to specify project information that will identify liquid fuel filtration requirements. In addition to requirements listed in the Liquid Fuel Suitability Form, the properties of the Biodiesel fuels must be tested per the requirements in Table 9.



Liquid Fuel
Suitability Form.doc