APPENDIX A

DATA ACQUISITION SYSTEM (DAS) DETAILS

AND

ONE TIME READINGS, SENSOR VERIFICATION/CALIBRATION DETAILS

Table A-1. Data Logger Channel Assignments and Sensor Identification

LOGGER	Data Pt Type	Data Pt Name	Description	Eng. Units	Sensor/Transducer
AM9-1	A1	TAO	Outdoor Air Temperature	F	Mamac TE211Z-E-E-2-na-1-E-3 (-30-130)
AM4-2	A2	RHO	Outdoor Humidity	%RH	Vaisala HMD60U
SE9	A4	TGE	Glycol Temperature Entering Unifin	F	Type T TC (high Temp)
SE10	A3	TGL	Glycol Temperature Leaving Unifin	F	Type T TC (high Temp)
AM9-2	A5	FGLY	Glycol Flowrate	gpm	Onicon F-1110, 4-20 ma
AM6-2	A6	IUP	Glycol Pump Current	amps	Veris H721LC (0 to 10 amp)
SE11	A7	TEXH1	Temperature of Turbine Exhaust	F	Type T TC (high Temp)
SE12	A8	TEXH2	Temperature of Unifin Exhaust	F	Type T TC (high Temp)
AM1-1	A9	TAR	Temperature Return Air to Munters	F	Mamac TE211Z-E-E-2-na-1-E-2 (40-140)
AM3-1	A10	RHR	RH Return Air to Munters	%RH	Vaisala HMD60U
AM2-2	A11	TCE	Temperature Entering DX/HR Coil	F	Mamac TE211Z-E-E-2-na-1-E-2 (40-140)
AM1-2	A13	TAS	Temperature Supply Air from Munters	F	Mamac TE211Z-E-E-2-na-1-E-2 (40-140)
AM3-2	A12	RHS	RH of Supply Air from Munters	%RH	Vaisala HMD60U
SE2	A14	TRE	Temperature Entering Regen Burner	F	Type T TC (high Temp)
SE7	A15	TR	Regen Temperature Entering Des Wheel	F	Type T TC (high Temp)
SE8	A16	TRL	Regen Temperature Leaving Des Wheel	F	Type T TC (high Temp)
AM2-1	A17	TWE	Temperature Entering Des Wheel	F	Mamac TE211Z-E-E-2-na-1-E-2 (40-140)
AM4-1	A18	RHWE	RH Entering Des Wheel	%RH	Vaisala HMD60U
AM10-1	A19	TWL	Temperature Leaving Des. Wheel	F	Vaisala HMP233 1% & 0.4F
AM10-2	A20	RHWL	RH Leaving Des Wheel	%RH	
AM8-2	A21	PEXH	Static Pressure, Turbine Exhaust	in H2O	Setra 267/Pitot Tube (MR)
AM8-1	A22	VEXH	Exhaust Gas Velocity	in H2O	Setra 267/Pitot Tube (MR)
AM7-1	A23	VRG	Regeneration Air Velocity	in H2O	Setra 267/Pitot Tube (MR)
AM7-2	A24	VPR	Process Air Velocity	in H2O	Setra 267/Pitot Tube (MR)
AM5-1	A25	ISF	Supply Fan Current	amps	Veris H721LC (0 to 10 amp)
AM 5-2	A26	IPF	Process Fan Current	amps	Veris H721LC (0 to 10 amp)
AM6-1	A27	IRF	Regen Fan Current	amps	Veris H721LC (0 to 10 amp)
AM11-1	A28	CAR	CO_2 Concentration in Return Duct	ppm	Telaire 8102
AM11-2	A29	CAS	CO_2 Concentration in Supply Duct	ppm	Telaire 8102
AM12-1	A30	CAO	CO_2 Concentration of Outdoor Air	ppm	Telaire 8102
	SYS2	WU	Utility Meter Power (kW, Amps, Volts)	kWh	Veris 8036 series
	SYS2	WT	Turbine Power Output (kW, Amps, Volts)	kWh	Veris 8036 series
P1	P1	FGT	Capstone Turbine Gas Use	cf	Roots, T-comp. 100 cf/p
P2	P2	FGM	Munters Unit Gas Use	cf	Roots, T-comp. 2 cf/p
C7	P3	WM	Munters Unit Power Use	kWh	Veris 8050 series
C8	P4	WGC	Gas Compressor Power	kWh	Veris 8050 series
DM1	D1	FC	DX Coil Condensate Drain	lb	HydroLynx tipping bucket
DM2	D2	SC1	Status, Munters Compressor Stage #1	minutes	Veris H800
DM3	D3	SC2	Status, Munters Compressor Stage #2	minutes	Veris H800
DM4	D4	SDH	Status, Munters Burner/Process Fan	minutes	Veris H800
DM5	D5	SH1	Status, Munters Heat Section, Stage 1	minutes	Veris H800
DM6	D6	SH2	Status, Munters Heat Section, Stage 2	minutes	Veris H800
DM7	D7	SUD	Status, Unifin Damper	minutes	Veris H800
DM8	D8	SV	Status, Glycol Control Valve	minutes	Veris H800
	D9	SSF	Status, Munters Supply Fan	minutes	Derived from ISF
	D10	SPF	Status, Munters Process Fan	minutes	Derived from IPF
	D11	SRF	Status, Munters RegenFan	minutes	Derived from IRF
	D12	SUP	Status, Unifin Pump	minutes	Derived from IUP

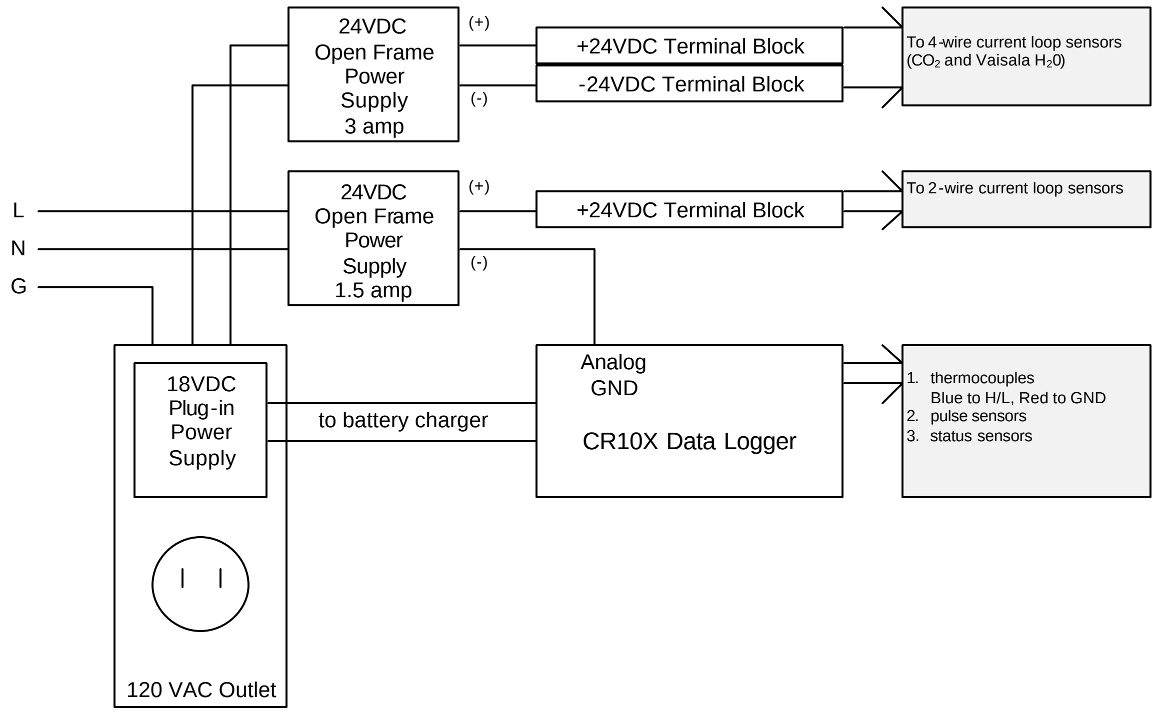


Figure A-1. DAS Enclosure Wiring Schematic

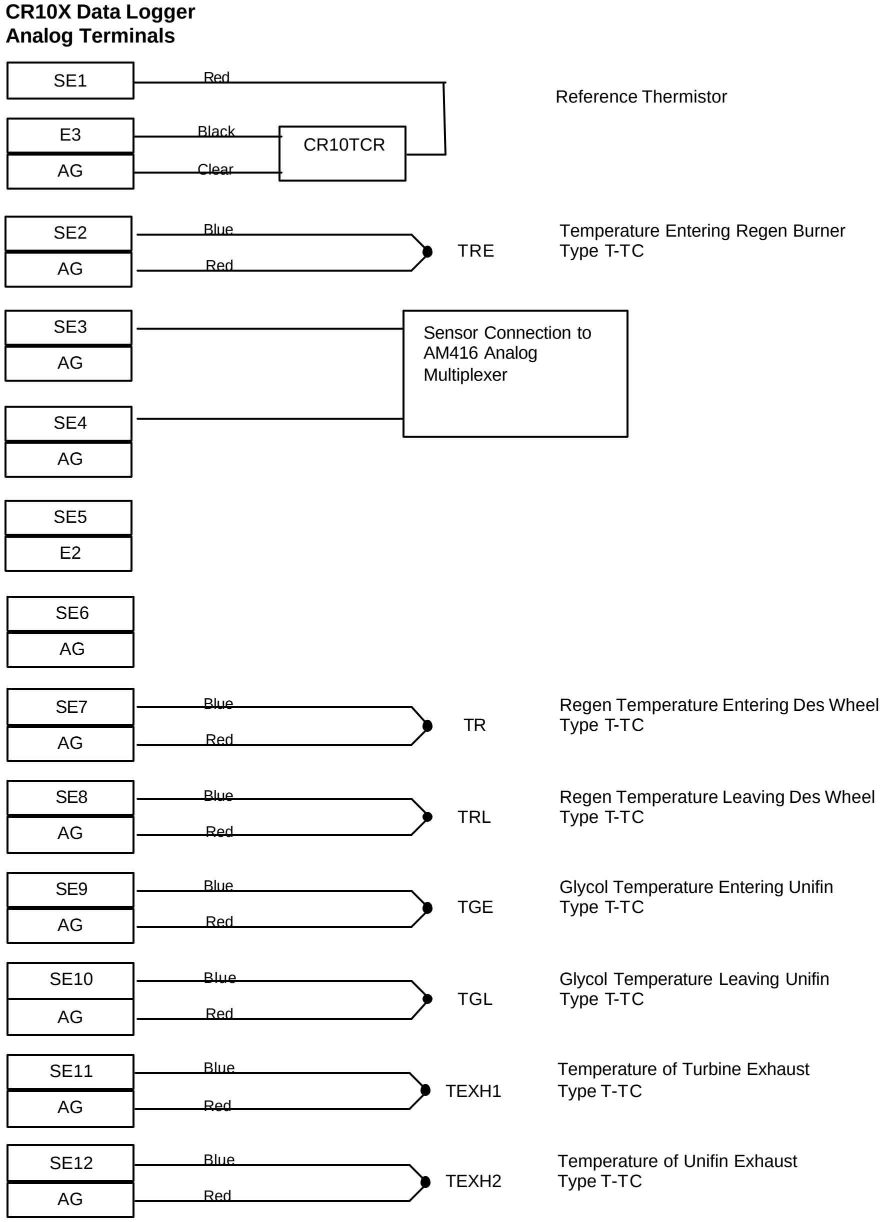


Figure A-2. CR10X Analog Terminals Wiring Schematic

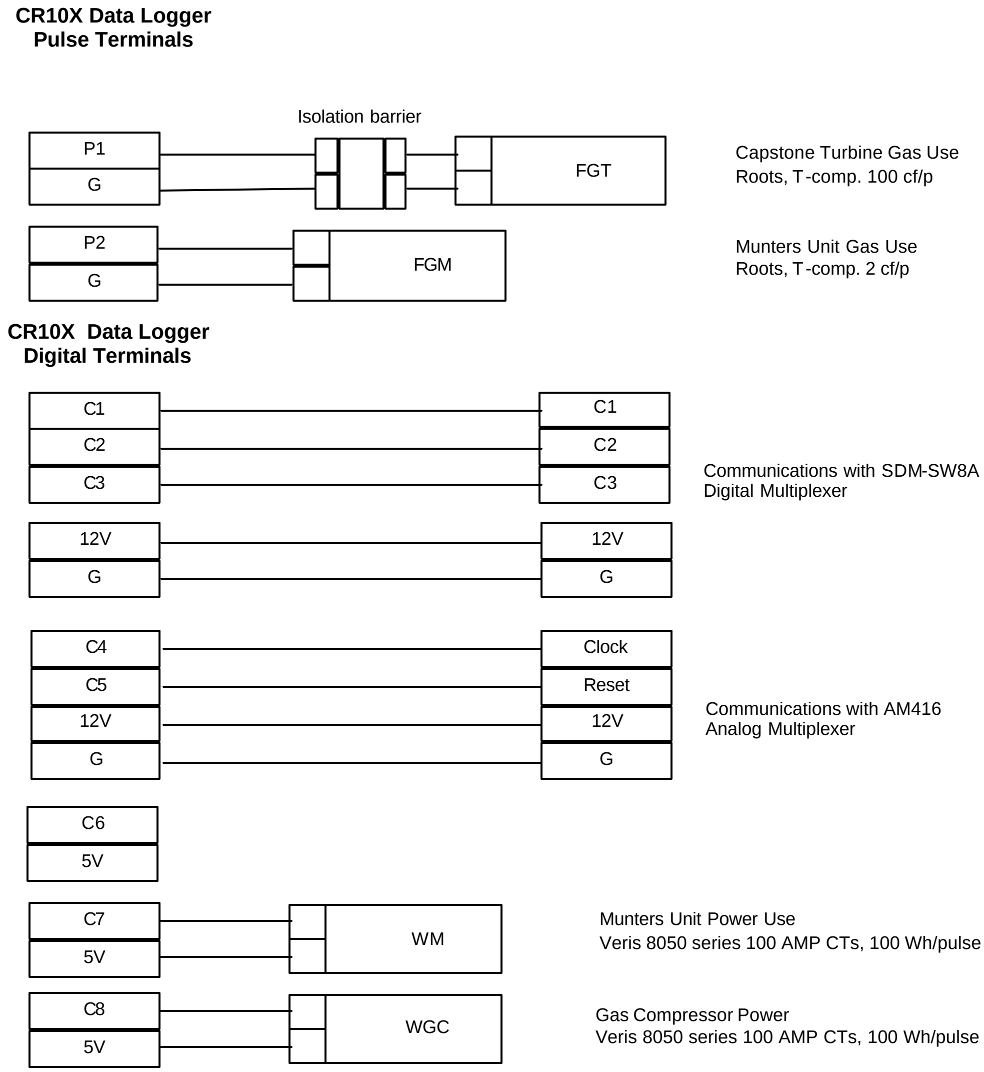


Figure A-3. CR10X Digital Terminals Wiring Schematic

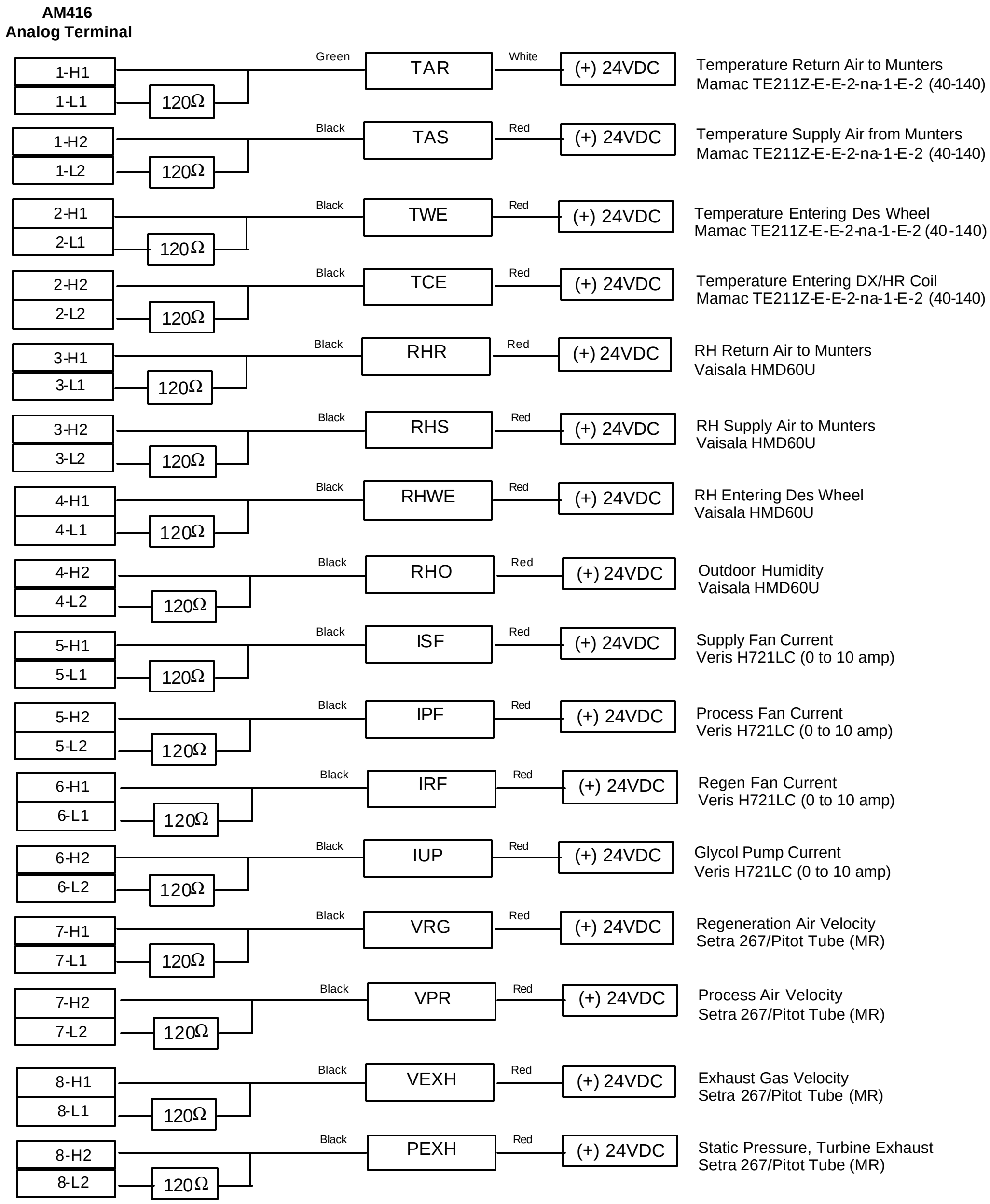


Figure A-4. Data Logger Connections to AM416

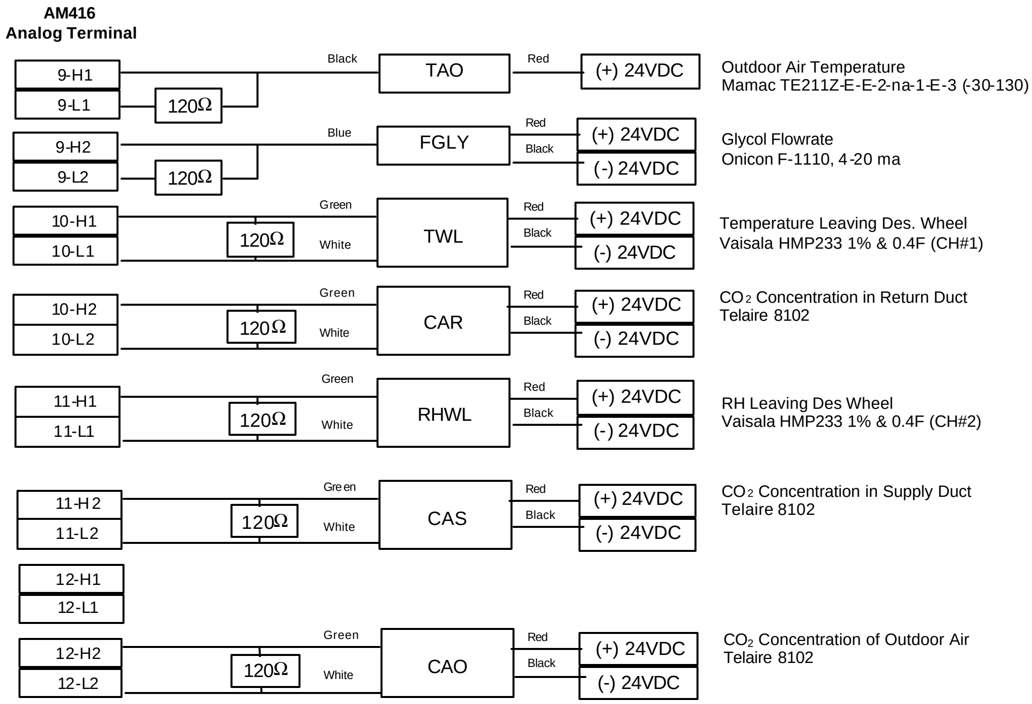


Figure A-5. Data Logger Connections to AM416 (con't)

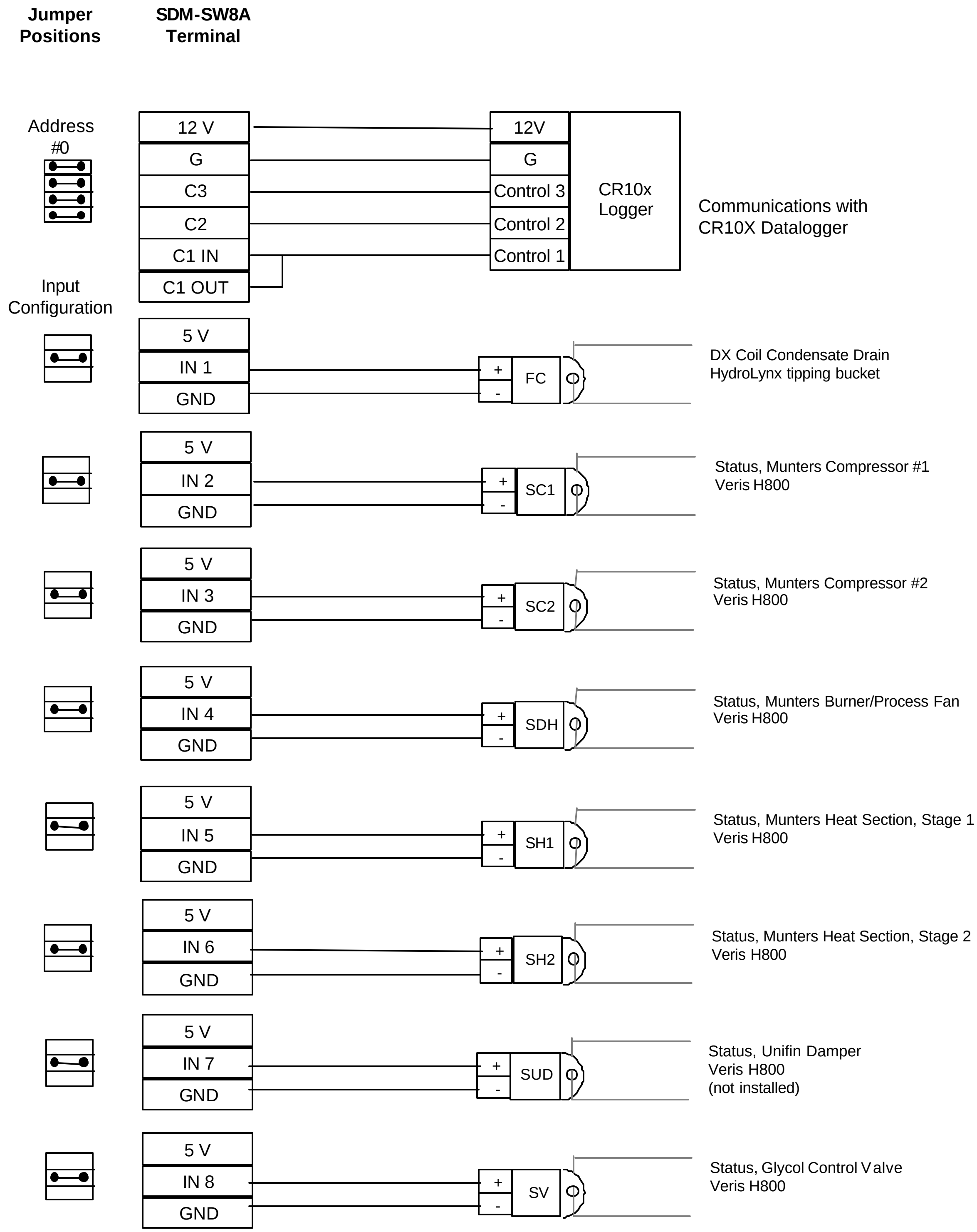


Figure A-6. Data Logger Connections to SDM-SW8A #0

Datalogger Program

```
;{CR10X}
;
;
;  Waldbaums Haupauge Long Island NY
;  1 MB CR10X
;  Logger Phone Number 1-(631)-979-3756
;
;  History:
;    Created by ACW 8/16/2002
;
;  Flags:
;
;    F2 - activate pulse accumulators (for on-site verification)
;    F3 - start one minute data
;    F8 - initialize readings
;
;       Output Array
;       1       xx      Campbell Output Code
;       2       ID      Record ID (0 - 15 minute, 5 - 1 minute data)
;       3       Year
;       4       HHMM
;       5       Day
;       6       Sec
;
;       When ID = 0, 5 (15, 1 minute data):
;       7       TAO     Outdoor Air Temperature                 AM9-1
;       8       RHO     Outdoor Humidity                        AM4-2
;       9       TGE     Glycol Temperature Entering Unifin      SE9
;       10      TGL     Glycol Temperature Leaving Unifin       SE10
;       11      FGLY    Glycol Flowrate                         AM9-2
;       12      IUP     Glycol Pump Current                     AM6-2
;       13      TEXH1   Temperature of Turbine Exhaust          SE11
;       14      TEXH2   Temperature of Unifin Exhaust           SE12
;       15      TAR     Temperature Return Air to Munters       AM1-1
;       16      RHR     RH Return Air to Munters                AM3-1
;       17      TCE     Temperature Entering DX/HR Coil         AM2-2
;       18      TAS     Temperature Supply Air from Munters     AM1-2
;       19      RHS     RH of Supply Air from Munters           AM3-2
;       20      TRE     Temperature Entering Regen Burner       SE2
;       21      TR      Regen Temperature Entering Des Wheel    SE7
;       22      TRL     Regen Temperature Leaving Des Wheel     SE8
;       23      TWE     Temperature Entering Des Wheel          AM2-1
;       24      RHWE    RH Supply Air from Munters              AM4-1
;       25      TWL     Temperature Leaving Des. Wheel          AM10-1
;       26      RHWL    Absolute Humidity Leaving Des Wheel     AM11-1
;       27      PEXH    Static Pressure, Turbine Exhaust        AM8-2
;       28      VEXH    Exhaust Gas Velocity                    AM8-1
;       29      VRG     Regeneration Air Velocity               AM7-1
;       30      VPR     Process Air Velocity                    AM7-2
;       31      ISF     Supply Fan Current                      AM5-1
;       32      IPF     Process Fan Current                     AM5-2
;       33      IRF     Regen Fan Current                       AM6-1
;       34      CAR     CO2 Concentration in Return Duct        AM10-2
;       35      CAS     CO2 Concentration in Supply Duct        AM11-2
;       36      CAO     CO2 Concentration of Outdoor Air        AM12-2
;       37      FGT     Capstone Turbine Gas Use                P1
;       38      FGM     Munters Unit Gas Use                    P2
;       39      WM      Munter Unit Power Use                   C7
;       40      WGC     Gas Compressor Power                    C8
;       41      FC      DX Coil Condensate Drain                DM0-1
;       42      SC1     Status, Munters Compressor #1           DM0-2
;       43      SC2     Status, Munters Compressor #2           DM0-3
;       44      SDH     Status, Munters Burner/Process Fan      DM0-4
;       45      SH1     Status, Munters Heat Section, Stage 1   DM0-5
;       46      SH2     Status, Munters Heat Section, Stage 2   DM0-6
;       47      SUD     Status, Unifin Damper                   DM0-7
;       48      SV      Status, Glycol Control Valve            DM0-8
;       49      SSF     Status, Munters Supply Fan              from
ISF
;       50      SPF     Status, Munters Process Fan             from
IPF
;       51      SRF     Status, Munters Regen Fan               from
IRF
;       52      SUP     Status, Unifin Pump                     from
IUP
;       53      TREF    Thermocouple Reference Temperature      SE1
;       54      VBAT    Battery Voltage                         -
;       55      QHR     Intergrated Heat Recovery               -

*Table A1 Program
  01: 5         Execution Interval (seconds)

;***** SCAN RATE CONSTANTS *****

1:  Z=F (P30)
 1: 60       F
 2: 0        Exponent of 10
 3: 1        Z Loc [ SIXTY     ]


2:  Z=F (P30)
 1: 5        F
 2: 0        Exponent of 10
 3: 2        Z Loc [ SCAN_SEC  ]

3:  Z=X/Y (P38)
 1: 2        X Loc [ SCAN_SEC  ]
 2: 1        Y Loc [ SIXTY     ]
 3: 3        Z Loc [ SCAN_MIN  ]

4:  Z=X/Y (P38)
 1: 3        X Loc [ SCAN_MIN  ]
 2: 1        Y Loc [ SIXTY     ]
 3: 4        Z Loc [ SCAN_HR   ]

;***** INITALIZE LOGGER WITH F8 *****

5:  If Flag/Port (P91)
 1: 28       Do if Flag 8 is Low
 2: 30       Then Do

     6:  Beginning of Loop (P87)
      1: 0        Delay
      2: 50       Loop Count

          7:  Z=F (P30)
           1: 0        F
           2: 0        Exponent of 10
           3: 5     -- Z Loc [ TREF_C    ]

     8:  End (P95)

9:  End (P95)

10:  Do (P86)
 1: 18       Set Flag 8 High

;***** BATTERY VOLTAGE AND REFERENCE TEMPERATURE
*****

11:  Batt Voltage (P10)
 1: 6        Loc [ VBAT_V    ]


12:  Temp (107) (P11)
 1: 1        Reps
 2: 1        SE Channel
 3: 3        Excite all reps w/E3
 4: 5        Loc [ TREF_C    ]
 5: 1.0      Mult
 6: 0.0      Offset



;***** READ SENSORS *****

;     SINGLE ENDED THERMOCOUPLE
;     0-7.5 mV TYPE T THERMOCOUPLE

13:  Thermocouple Temp (SE) (P13)
 1: 4        Reps
 2: 22       7.5 mV 60 Hz Rejection Range
 3: 7        SE Channel
 4: 1        Type T (Copper-Constantan)
 5: 5        Ref Temp Loc [ TREF_C    ]
 6: 7        Loc [ TR        ]
 7: 1.8      Mult
 8: 32       Offset

14:  Thermocouple Temp (SE) (P13)
 1: 1        Reps
 2: 22       7.5 mV 60 Hz Rejection Range
 3: 2        SE Channel
 4: 1        Type T (Copper-Constantan)
 5: 5        Ref Temp Loc [ TREF_C    ]
 6: 11       Loc [ TRE       ]
 7: 1.8      Mult
 8: 32       Offset

;     SINGLE ENDED THERMOCOUPLE
;     0-25 mV TYPE T THERMOCOUPLE

15:  Thermocouple Temp (SE) (P13)
 1: 2        Reps
 2: 23       25 mV 60 Hz Rejection Range
```

```
 3: 11       SE Channel
 4: 1        Type T (Copper-Constantan)
 5: 5        Ref Temp Loc [ TREF_C    ]
 6: 12       Loc [ TEHX1     ]
 7: 1.8      Mult
 8: 32       Offset

;     AM416 MULTIPLEXER

16:  Do (P86)
 1: 45       Set Port 5 High

17:  Do (P86)
 1: 76       Pulse Port 6

18:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     TAR, TAS, TWE, TCE TEMPERATURE SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     40 TO 140 F RANGE

     19:  Volts (SE) (P1)
      1: 2       Reps
      2: 25      2500 mV 60 Hz Rejection Range
      3: 3       SE Channel
      4: 14      Loc [ TAR       ]
      5: .052083  Mult
      6: 15      Offset

20:  Do (P86)
 1: 76       Pulse Port 6

21:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

     22:  Volts (SE) (P1)
      1: 2       Reps
      2: 25      2500 mV 60 Hz Rejection Range
      3: 3       SE Channel
      4: 16      Loc [ TWE       ]
      5: .052083  Mult
      6: 15      Offset


23:  Do (P86)
 1: 76       Pulse Port 6

24:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     RHR, RHS, RHWE, RHO RH SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 100% RANGE

     25:  Volts (SE) (P1)
      1: 2       Reps
      2: 25      2500 mV 60 Hz Rejection Range
      3: 3       SE Channel
      4: 18      Loc [ RHR       ]
      5: .052083  Mult
      6: -25     Offset

26:  Do (P86)
 1: 76       Pulse Port 6

27:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

28:  Volts (SE) (P1)
 1: 2        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 20       Loc [ RHWE      ]
 5: .052083  Mult
 6: -25      Offset


29:  Do (P86)
 1: 76       Pulse Port 6

30:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     ISF, IPF, CURRENT SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 20 AMP RANGE

31:  Volts (SE) (P1)
 1: 2        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 22       Loc [ ISF       ]
 5: .010417  Mult
 6: -5       Offset

32:  Do (P86)
 1: 76       Pulse Port 6

33:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     IRF, IUP, CURRENT SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 20 AMP RANGE IRF
;     0 TO 30 AMP RANGE IUP

34:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 24       Loc [ IRF       ]
 5: .010417  Mult
 6: -5       Offset

35:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 25       Loc [ IUP       ]
 5: .015625  Mult
 6: -7.5     Offset


36:  Do (P86)
 1: 76       Pulse Port 6

37:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     VPR, VRG, AIR VELOCITY PITOT TUBES
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 0.5 IN WC *1000 RANGE

38:  Volts (SE) (P1)
 1: 2        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 26       Loc [ VPR       ]
 5: .260417  Mult
 6: -125     Offset
```

```
39:  Do (P86)
 1: 76       Pulse Port 6

40:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     VEXH, PEXH, AIR VELOCITY PITOT TUBES
;     4-20 mA ON 120 ohm RESISTOR
;     VEXH 0 TO 0.1 IN WC *1000 RANGE
;     VEXH 0 TO 7.5 IN WC *1000 RANGE

41:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 28       Loc [ VEXH      ]
 5: .260417  Mult
 6: -125     Offset

42:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 29       Loc [ PEXH      ]
 5: 3.90625  Mult
 6: -1875    Offset

43:  Do (P86)
 1: 76       Pulse Port 6

44:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     TAO, TEMPERATURE SENSOR
;     FGLY GLYCOL FLOWMETER
;     4-20 mA ON 120 ohm RESISTOR
;     TAO -30 TO 130 F RANGE
;     FGLY 0 TO 80 GPM RANGE

45:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 30       Loc [ TAO       ]
 5: .083333  Mult
 6: -70      Offset

46:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 31       Loc [ FGLY      ]
 5: .041667  Mult
 6: -20      Offset

47:  Do (P86)
 1: 76       Pulse Port 6

48:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation


;     TWL PRECISION TEMPERATURE
;     4-20 mA ON 120 ohm RESISTOR
;     TWL

49:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 32       Loc [ TWL       ]
 5: .09375   Mult
 6: -49      Offset

;     CAR, CO2 SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 2000 PPM RANGE

50:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 34       Loc [ CAR       ]
 5: 1.04166  Mult
 6: -500     Offset

51:  Do (P86)
 1: 76       Pulse Port 6

52:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation


;     RHWL PRECISION HUMIDITY SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     RHWL 0 TO 100% RANGE

53:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 3        SE Channel
 4: 33       Loc [ RHWL      ]
 5: .052083  Mult
 6: -25      Offset

;     CAS CO2 SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 2000 PPM RANGE

54:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 35       Loc [ CAS       ]
 5: 1.04166  Mult
 6: -500     Offset

55:  Do (P86)
 1: 76       Pulse Port 6

56:  Excitation with Delay (P22)
 1: 1        Ex Channel
 2: 0        Delay W/Ex (units = 0.01 sec)
 3: 10       Delay After Ex (units = 0.01 sec)
 4: 0        mV Excitation

;     CAO CO2 SENSORS
;     4-20 mA ON 120 ohm RESISTOR
;     0 TO 2000 PPM RANGE

57:  Volts (SE) (P1)
 1: 1        Reps
 2: 25       2500 mV 60 Hz Rejection Range
 3: 4        SE Channel
 4: 36       Loc [ CAO       ]
 5: 1.04166  Mult
 6: -500     Offset

58:  Do (P86)
 1: 55       Set Port 5 Low

;     FGT GAS METER PULSE
;     100 FT/PULSE

59:  Pulse (P3)
 1: 1        Reps
 2: 1        Pulse Channel 1
 3: 2        Switch Closure, All Counts
 4: 37       Loc [ FGT_CUFT  ]
```

```
 5: 100      Mult
 6: 0.0      Offset

;     FGM GAS METER PULSE
;     .2 FT/PULSE (50 pulse per 10 foot rev)

60:  Pulse (P3)
 1: 1        Reps
 2: 2        Pulse Channel 2
 3: 2        Switch Closure, All Counts
 4: 38       Loc [ FGM_CUFT  ]
 5: 0.2      Mult
 6: 0.0      Offset

;     WM, WGC POWER TRANSDUCER
;     100 Wh/PULSE

61:  Pulse (P3)
 1: 2        Reps
 2: 7        Control Port 7
 3: 2        Switch Closure, All Counts
 4: 39       Loc [ WM_KWH    ]
 5: 0.100    Mult
 6: 0.0      Offset

;     FC TIPPING BUCKET RAIN GAUGE
;     ??? mL/oz / pulse

62:  SDM-SW8A (P102)
 1: 1        Reps
 2: 0        Address
 3: 2        Counts function
 4: 1        Channel
 5: 41       Loc [ FC_PULSE  ]
 6: 1.0      Mult
 7: 0.0      Offset

;     SC1, SC2, SDH, SH1, SH2, SUD, SV CURRENT
STATUS SENSORS

63:  SDM-SW8A (P102)
 1: 7        Reps
 2: 0        Address
 3: 0        Channel state(s) function
 4: 2        Channel
 5: 42       Loc [ SC1_LOG   ]
 6: -1       Mult
 7: 1        Offset

;     SSF, SPF, SRF, SUP STATUS FROM ANALOG CURRENT

64:  Beginning of Loop (P87)
 1: 0        Delay
 2: 4        Loop Count

     65:  IF (X<=>F) (P89)
      1: 22    -- X Loc [ ISF       ]
      2: 3        >=
      3: 1        F
      4: 30       Then Do

          66:  Z=F (P30)
           1: 1        F
           2: 0        Exponent of 10
           3: 49    -- Z Loc [ SSF_LOG   ]

     67:  Else (P94)

          68:  Z=F (P30)
           1: 0        F
           2: 0        Exponent of 10
           3: 49    -- Z Loc [ SSF_LOG   ]

69:  End (P95)


70:  IF (X<=>F) (P89)
 1: 29       X Loc [ PEXH      ]
 2: 1        =
 3: 4700     F
 4: 30       Then Do

     71:  Z=F (P30)
      1: 1        F
      2: 0        Exponent of 10
      3: 47       Z Loc [ SUD_LOG   ]

72:  Else (P94)



     73:  Z=F (P30)
      1: 0        F
      2: 0        Exponent of 10
      3: 47       Z Loc [ SUD_LOG   ]

74:  End (P95)


;IF STATUSES ARE GREATER THAN ZERO NORMALIZE TO 1.0

75:  Beginning of Loop (P87)
 1: 0        Delay
 2: 11       Loop Count

     76:  IF (X<=>F) (P89)
      1: 42    -- X Loc [ SC1_LOG   ]
      2: 2        <>
      3: 0.0      F
      4: 30       Then Do

          77:  Z=F (P30)
           1: 1        F
           2: 0        Exponent of 10
           3: 42    -- Z Loc [ SC1_LOG   ]

     78:  End (P95)

     79:  Z=X*Y (P36)
      1: 42    -- X Loc [ SC1_LOG   ]
      2: 3        Y Loc [ SCAN_MIN  ]
      3: 53    -- Z Loc [ SC1_MIN   ]

80:  End (P95)


;***** PROGRAM LOGIC *****
;CALL 15-MINUTE ROUTINE

81:  Do (P86)
 1: 1        Call Subroutine 1

;CALL 1-MINUTE ROUTINE with FLAG 3


82:  If Flag/Port (P91)
 1: 13       Do if Flag 3 is High
 2: 30       Then Do

     83:  Do (P86)
      1: 2        Call Subroutine 2

84:  End (P95)


;***** ACCUMULATING LOGIC *****

85:  Z=X+Y (P33)
 1: 64       X Loc [ HR_ADD    ]
 2: 4        Y Loc [ SCAN_HR   ]
 3: 64       Z Loc [ HR_ADD    ]


86:  Beginning of Loop (P87)
 1: 0000     Delay
 2: 5        Loop Count

     87:  Z=X+Y (P33)
      1: 65    -- X Loc [ FGT_ADD   ]
      2: 37    -- Y Loc [ FGT_CUFT  ]
      3: 65    -- Z Loc [ FGT_ADD   ]
```

```
     88:  Z=X/Y (P38)
      1: 65    -- X Loc [ FGT_ADD   ]
      2: 64       Y Loc [ HR_ADD    ]
      3: 70    -- Z Loc [ FGT_CFH   ]

89:  End (P95)

90:  If Flag/Port (P91)
 1: 22       Do if Flag 2 is Low
 2: 30       Then Do

     91:  Beginning of Loop (P87)
      1: 0        Delay
      2: 11       Loop Count

          92:  Z=F (P30)
           1: 0        F
           2: 0        Exponent of 10
           3: 64    -- Z Loc [ HR_ADD    ]

     93:  End (P95)

94:  End (P95)

95:  Z=F (P30)
 1: .5       F
 2: 00       Exponent of 10
 3: 76       Z Loc [ mcp60_h2o ]

96:  Z=X*Y (P36)
 1: 31       X Loc [ FGLY      ]
 2: 76       Y Loc [ mcp60_h2o ]
 3: 77       Z Loc [ scratch1  ]

97:  Z=X-Y (P35)
 1: 10       X Loc [ TGL       ]
 2: 9        Y Loc [ TGE       ]
 3: 78       Z Loc [ delta_t   ]

98:  Z=X*Y (P36)
 1: 77       X Loc [ scratch1  ]
 2: 78       Y Loc [ delta_t   ]
 3: 79       Z Loc [ qhr       ]


99:  Z=X*Y (P36)
 1: 79       X Loc [ qhr       ]
 2: 4        Y Loc [ SCAN_HR   ]
 3: 79       Z Loc [ qhr       ]

100:  End (P95)

*Table A2 Program
  02: 0         Execution Interval (seconds)

*Table A3 Subroutines

;***** 15-MINUTE ROUTINE *****

1:  Beginning of Subroutine (P85)
 1: 1        Subroutine 1

     2:  If time is (P92)
      1: 0        Minutes (Seconds --) into a
      2: 15       Interval (same units as above)
      3: 10       Set Output Flag High (Flag 0)

     3:  Z=F (P30)
      1: 0        F
      2: 0        Exponent of 10
      3: 75       Z Loc [ ID       ]

     4:  Sample (P70)
      1: 1        Reps
      2: 75       Loc [ ID       ]

     5:  Real Time (P77)
      1: 1111     Year,Day,Hour/Minute,Seconds
(midnight = 0000)
```

```
6:  Resolution (P78)
 1: 1        High Resolution

7:  Average (P71)
 1: 1        Reps
 2: 30       Loc [ TAO       ]

8:  Average (P71)
 1: 1        Reps
 2: 21       Loc [ RHO       ]

9:  Average (P71)
 1: 2        Reps
 2: 9        Loc [ TGE       ]

10:  Average (P71)
 1: 1        Reps
 2: 31       Loc [ FGLY      ]

11:  Average (P71)
 1: 1        Reps
 2: 25       Loc [ IUP       ]

12:  Average (P71)
 1: 2        Reps
 2: 12       Loc [ TEHX1     ]

13:  Average (P71)
 1: 1        Reps
 2: 14       Loc [ TAR       ]

14:  Average (P71)
 1: 1        Reps
 2: 18       Loc [ RHR       ]

15:  Average (P71)
 1: 1        Reps
 2: 17       Loc [ TCE       ]

16:  Average (P71)
 1: 1        Reps
 2: 15       Loc [ TAS       ]

17:  Average (P71)
 1: 1        Reps
 2: 19       Loc [ RHS       ]

18:  Average (P71)
 1: 1        Reps
 2: 11       Loc [ TRE       ]

19:  Average (P71)
 1: 2        Reps
 2: 7        Loc [ TR        ]

20:  Average (P71)
 1: 1        Reps
 2: 16       Loc [ TWE       ]

21:  Average (P71)
 1: 1        Reps
 2: 20       Loc [ RHWE      ]

22:  Average (P71)
 1: 2        Reps
 2: 32       Loc [ TWL       ]

23:  Average (P71)
 1: 1        Reps
 2: 29       Loc [ PEXH      ]

24:  Average (P71)
 1: 1        Reps
 2: 28       Loc [ VEXH      ]

25:  Average (P71)
 1: 2        Reps
 2: 26       Loc [ VPR       ]

26:  Average (P71)
 1: 3        Reps
```

```
      2: 22       Loc [ ISF       ]

     27:  Average (P71)
      1: 3        Reps
      2: 34       Loc [ CAR       ]

     28:  Resolution (P78)
      1: 0        Low Resolution

     29:  Totalize (P72)
      1: 5        Reps
      2: 37       Loc [ FGT_CUFT  ]

     30:  Totalize (P72)
      1: 11       Reps
      2: 53       Loc [ SC1_MIN   ]

     31:  Average (P71)
      1: 2        Reps
      2: 5        Loc [ TREF_C    ]

     32:  Resolution (P78)
      1: 1        High Resolution

     33:  Totalize (P72)
      1: 1        Reps
      2: 79       Loc [ qhr       ]

34:  End (P95)

35:  Beginning of Subroutine (P85)
 1: 2        Subroutine 2

     36:  If time is (P92)
      1: 0        Minutes (Seconds --) into a
      2: 1        Interval (same units as above)
      3: 10       Set Output Flag High (Flag 0)

     37:  Z=F (P30)
      1: 5        F
      2: 0        Exponent of 10
      3: 75       Z Loc [ ID        ]

     38:  Sample (P70)
      1: 1        Reps
      2: 75       Loc [ ID        ]

     39:  Real Time (P77)
      1: 1111     Year,Day,Hour/Minute,Seconds
(midnight = 0000)

     40:  Resolution (P78)
      1: 1        High Resolution

     41:  Average (P71)
      1: 1        Reps
      2: 30       Loc [ TAO       ]

     42:  Average (P71)
      1: 1        Reps
      2: 21       Loc [ RHO       ]

     43:  Average (P71)
      1: 2        Reps
      2: 9        Loc [ TGE       ]

     44:  Average (P71)
      1: 1        Reps
      2: 31       Loc [ FGLY      ]

     45:  Average (P71)
      1: 1        Reps
      2: 25       Loc [ IUP       ]

     46:  Average (P71)
      1: 2        Reps
      2: 12       Loc [ TEHX1     ]

     47:  Average (P71)
      1: 1        Reps
      2: 14       Loc [ TAR       ]

     48:  Average (P71)
      1: 1        Reps
      2: 18       Loc [ RHR       ]

     49:  Average (P71)
      1: 1        Reps
      2: 17       Loc [ TCE       ]

     50:  Average (P71)
      1: 1        Reps
      2: 15       Loc [ TAS       ]

     51:  Average (P71)
      1: 1        Reps
      2: 19       Loc [ RHS       ]

     52:  Average (P71)
      1: 1        Reps
      2: 11       Loc [ TRE       ]

     53:  Average (P71)
      1: 2        Reps
      2: 7        Loc [ TR        ]

     54:  Average (P71)
      1: 1        Reps
      2: 16       Loc [ TWE       ]

     55:  Average (P71)
      1: 1        Reps
      2: 20       Loc [ RHWE      ]

     56:  Average (P71)
      1: 2        Reps
      2: 32       Loc [ TWL       ]

     57:  Average (P71)
      1: 1        Reps
      2: 29       Loc [ PEXH      ]

     58:  Average (P71)
      1: 1        Reps
      2: 28       Loc [ VEXH      ]

     59:  Average (P71)
      1: 2        Reps
      2: 26       Loc [ VPR       ]

     60:  Average (P71)
      1: 3        Reps
      2: 22       Loc [ ISF       ]

     61:  Average (P71)
      1: 3        Reps
      2: 34       Loc [ CAR       ]

     62:  Resolution (P78)
      1: 0        Low Resolution

     63:  Totalize (P72)
      1: 5        Reps
      2: 37       Loc [ FGT_CUFT  ]

     64:  Totalize (P72)
      1: 11       Reps
      2: 53       Loc [ SC1_MIN   ]

     65:  Average (P71)
      1: 2        Reps
      2: 5        Loc [ TREF_C    ]

     66:  Resolution (P78)
      1: 1        High Resolution

     67:  Totalize (P72)
      1: 1        Reps
      2: 79       Loc [ qhr       ]

68:  End (P95)
End Program
```

Sensor Verification/Calibration and One-Time Readings

An stirred ice water bath was used to verify the temperature sensors for the turbine exhaust and glycol loop. The four type-T thermocouples registered readings close to 32°F.

Table A-2. Temperature Sensor Calibration Measurements using an Ice Water Bath

	August 27, 2002 Comparison to ice water bath at 32°F
Sensor	DAS Reading
TEHX1	31.6°F
TEHX1	31.9°F
TGE	32.1°F
TGL	32.2°F

SRI also asked CDH to perform a three-point calibration of Glycol thermocouples with their NIST-traceable Fluke TC Meter. The two thermocouples were wire-tied together with the Fluke sensorfor the test. The test was performed in July 2003 and the results are summarized in the table below.

Table A-3. Glycol Temperature Three-point Calibration

	Test 1 (ambient)	Test 2 (ice bath)	Test 3 (ambient)
Fluke TC Meter	95.2	32.0	82.4
TGL	95.7	28.3	82.8
TGE	96.2	29.4	83.6

Several one-time measurements were taken using handheld instruments to verify that the data logger was functioning properly. The measurements are shown in the tables below.

Table A-4. One-Time Measurements – October 17, 2002

	October 17, 2002	
Sensor	DAS Reading	Handheld Reading
TEHX1	610°F	601°F (Unifin thermistor)
TEHX1	545°F	544°F (Unifin thermistor)
TGE	165°F	169°F
TGL	172°F	177°F
PEXH	4.8 in WC	4.7 in WC
VEXH	0.45 in WC	0.44 in WC
IUP	5.7 amps	5.7 amps
WGC	3.90 kW	3.95 kW

Table A-5. One-Time Power Readings – August 27, 2002

Load	Amps (A/B/C) @ 471 VAC	Measured Power (kW)
Supply Fan	16.1 / 17.1 / 16.8	10.85 kW
Regeneration Fan	7.7 / 8.1 / 8.1	5.30 kW
Process Fan	9.9 / 10.3 / 10.3	6.05 kW
Cooling Stage #1	18.3 / 21.2 / 22.6	12.05 kW
Cooling Stage #2	19.7 / 23.5 / 18.9	12.30 kW
Total Unit	79.5 / 86.3 / 82.8	56.40 kW

One-time readings were taken at various times during the monitoring to ensure the accuracy of the Sensors in the Munters AHU.

Table A-6. One-time Sensor Readings

	August 27, 2002		October 17, 2002		July 8, 2003		September 17, 2003	
Sensor	**DAS Reading**	**Handheld Reading (TSI probe)**	**DAS Reading**	**Handheld Reading (TSI probe)**	**DAS Reading**	**Handheld Reading (TSI probe)**	**DAS Reading**	**Handheld Reading (TSI probe)**
TAO	81.3°F	79.9°F	55.6°F	54.0°F				
TAO2							76.3°F	76.7°F
RHO	48.0%	50.8%	51.4%	50.0%			**41.5%**	**47.1%**
TAR	72.2°F	71.8°F	72.1°F	72.6°F	79.0°F	77.7°F	70.9°F	70.3°F
RHR	40.3%	42.4%	17.5%	16.5%	**34.0%**	**40.0%**	**43.5%**	**49.2%**
TWE	80.5°F	79.0°F	63.0°F	63.9°F	90.2°F	89.8°F		
RHWE	51.1%	52.3%	49.5%	49.0%	**40.0%**	**47.8%**		
TWL (des off)	86.0°F	86.5°F					74.9°F	75.6°F
RHWL (des off)	28.5%	29.9%					43.1%	48.5%
TWL (des on)	117.0°F	117.4°F	89.5°F	90.9°F	122.5°F	123.7°F		
RHWL (des on)	7.2%	6.3%	1.1%	0.0%	6.4%	6.4%		
TCE					72.0°F	74.5°F	71.3°F	71.0°F
TAS			85.6°F	85.5°F	99.0°F	103.3°F	74.5°F	74.3°F
RHS			3.9%	4.5%	**24.0%**	**19.6%**	**41.3%**	**46.1%**
VPR			0.36 in WC	0.36 in WC				
VRG			0.25 in WC	0.27 in WC				
TRE					154.0°F	153.8°F		
TR					228.0°F	233.6°F		
TRL					129.0°F	128.0°F		
ISF	16.8 amps	16.6 amps						
IRF	7.5 amps	7.9 amps						
IPF	9.6 amps	10.2 amps						
WM	56.4 kW	55.5 kW						

Notes:

1) TSI was factory calibrated in April 2003. Temperature calibration was unchanged. RH calibration increased reading by 1.2% near 30% rh..

2) All the Vaisala RH conventional ±2% sensors (RHO, RHR, RHS, RHWE) drifted up by 4-6% rh in the 2003 season. These are shown as bold.

Pitot tubes were used to take single point velocity readings at several locations in the Munters desiccant section and in the microturbine exhaust duct. The air velocity from the measured pitot tube pressure difference is determined by:

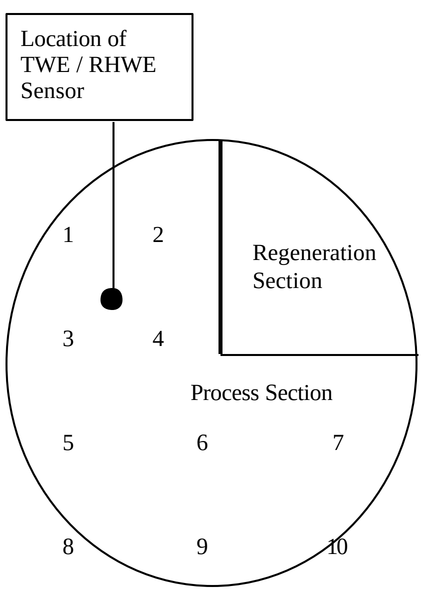
$$SFPM = 4005\sqrt{\frac{r}{r_{std}}} \times \sqrt{\Delta P}$$

Where:	4005	=	constant for standard air conditions
	ρ	=	density for air in air stream
	ρ_{std}	=	density for air at standard conditions (0.075 lb/ft^3)
	ΔP	=	measured pitot tube pressure differential (in. WC)

The conditions entering the desiccant wheel were highly stratified and had to measured with the handheld TSI probe. Handheld readings were taken to determine the distribution of entering wheel conditions. One set of readings were taken in the center of each of the 10 filters covering the process section of the desiccant wheel. The readings and a diagram are shown in the table below.

Table A-7. Desiccant Wheel Stratification Measurements

TWE / RHWE sensor reading at time of test
63.0 °F, 49.5% RH, 42.2 gr/lb



Location	Temperature (°F)	RH (%)	Abs. Humidity (gr/lb)
1	64.9	48.7	44.3
2	63.5	52.1	45.2
3	63.9	47.0	41.4
4	77.2	18.5	25.4
5	61.4	54.3	43.7
6	60.9	54.9	43.4
7	68.8	32.2	33.4
8	74.2	21.5	26.8
9	77.9	19.8	28.0
10	75.8	19.8	26.1
AVG	68.8	36.9	35.8

The distribution around the wheel indicates that the actual conditions entering the wheel are 6.4 gr/lb drier than indicated by the DAS sensor. Data collected for the TWE and RHWE sensors were adjusted accordingly.

Comparing CDH and SRI Readings at Waldbaums CHP System

The Southern Research Institute (SRI) installed additional instrumentation on the Capstone 60 kW Microturbine at Waldbaums as part of the ETV testing program. The additional instrumentation included:

- A Ion 7600 series power transducer from PMI
- A Rosemount gas flow meter with pressure and temperature compensation

The CDH power meters were Veris 8036 series self-contained units installed at the MDP. Gas use was measured by pulses from a compensated Roots utility meter.

Table 1 compares the readings taken for the eighteen 30-minute runs that were completed on June 4 and 5. The CDH data records are the average of 15-minute intervals. The SRI data were averaged over 1-minute intervals. The SRI runs were made on groups of three (i.e., 1,2,3 are at condition 1, while 4,5,6 are at condition 2) so in some cases the third run in a series could not be used since the 15-minute from CDH record may have crossed the boundary. Therefore, the third run in many series could not be compared.

Table A-8. Comparing CDH and SRI Readings

		No of Records		Turbine Power				Avg Turbine Current			
Run	Period	CDH	SRI	CDH	SRI	Abs Diff	% Diff	CDH	SRI	Abs Diff	% Diff
1	06/04/03 13:06:00 - 06/04/03 13:35:00	2	30	56.62	59.59	-2.97	-5.0%	66.72	68.84	-2.12	-3.1%
2	06/04/03 13:46:00 - 06/04/03 14:15:00	2	30	56.63	59.56	-2.93	-4.9%	66.43	68.82	-2.39	-3.5%
3	06/04/03 14:26:00 - 06/04/03 14:55:00	2	30	43.30	59.56			41.73	68.69		
4	06/04/03 15:41:00 - 06/04/03 16:10:00	2	30	56.64	59.54	-2.9	-4.9%	66.70	68.56	-1.86	-2.7%
5	06/04/03 16:21:00 - 06/04/03 16:50:00	2	30	56.64	59.55	-2.91	-4.9%	66.50	68.54	-2.04	-3.0%
6	06/04/03 17:01:00 - 06/04/03 17:29:00	2	29	56.64	59.56	-2.92	-4.9%	66.54	68.57	-2.03	-3.0%
7	06/05/03 10:16:00 - 06/05/03 10:45:00	2	30	42.42	44.52	-2.1	-4.7%	50.46	51.84	-1.38	-2.7%
8	06/05/03 11:01:00 - 06/05/03 11:30:00	2	30	42.45	44.52	-2.07	-4.6%	50.43	51.94	-1.51	-2.9%
9	06/05/03 11:41:00 - 06/05/03 12:10:00	2	30	30.94	44.53			33.41	51.97		
10	06/05/03 12:36:00 - 06/05/03 13:05:00	2	30	28.18	29.49	-1.31	-4.4%	33.23	34.63	-1.4	-4.0%
11	06/05/03 13:16:00 - 06/05/03 13:45:00	2	30	28.20	29.49	-1.29	-4.4%	33.53	34.61	-1.08	-3.1%
12	06/05/03 13:56:00 - 06/05/03 14:25:00	2	30	28.18	29.48	-1.3	-4.4%	33.40	34.62	-1.22	-3.5%
13	06/05/03 14:46:00 - 06/05/03 15:15:00	2	30	28.06	29.49	-1.43	-4.8%	33.29	34.37	-1.08	-3.1%
14	06/05/03 15:26:00 - 06/05/03 15:55:00	2	30	28.20	29.49	-1.29	-4.4%	33.27	34.39	-1.12	-3.3%
15	06/05/03 16:06:00 - 06/05/03 16:35:00	2	30	13.76	29.49			16.46	34.46		
16	06/05/03 16:46:00 - 06/05/03 17:15:00	2	30	13.70	14.46	-0.76	-5.3%	16.36	17.19	-0.83	-4.8%
17	06/05/03 17:26:00 - 06/05/03 17:55:00	2	30	13.68	14.46	-0.78	-5.4%	16.47	17.14	-0.67	-3.9%
18	06/05/03 18:05:00 - 06/05/03 18:34:00	2	30	27.12	14.46			41.57	17.16		

		No of Records		MDP Voltage				Turbine Gas Input			
Run	Period	CDH	SRI	CDH	SRI	Abs Diff	% Diff	CDH	SRI	Abs Diff	% Diff
1	06/04/03 13:06:00 - 06/04/03 13:35:00	2	30	492.89	489.67	3.22	0.7%	800	793.18	6.82	0.9%
2	06/04/03 13:46:00 - 06/04/03 14:15:00	2	30	494.83	490.03	4.8	1.0%	800	792.75	7.25	0.9%
3	06/04/03 14:26:00 - 06/04/03 14:55:00	2	30	494.22	491.15	3.07	0.6%	400	792.05		
4	06/04/03 15:41:00 - 06/04/03 16:10:00	2	30	494.46	492.05	2.41	0.5%	800	793.58	6.42	0.8%
5	06/04/03 16:21:00 - 06/04/03 16:50:00	2	30	494.65	491.78	2.87	0.6%	600	794.44	-194.44	-24.5%
6	06/04/03 17:01:00 - 06/04/03 17:29:00	2	29	494.81	491.58	3.23	0.7%	800	795.06	4.94	0.6%
7	06/05/03 10:16:00 - 06/05/03 10:45:00	2	30	491.25	488.78	2.47	0.5%	400	618.84	-218.84	-35.4%
8	06/05/03 11:01:00 - 06/05/03 11:30:00	2	30	491.13	487.70	3.43	0.7%	600	623.32	-23.32	-3.7%
9	06/05/03 11:41:00 - 06/05/03 12:10:00	2	30	491.72	487.46	4.26	0.9%	400	624.15		
10	06/05/03 12:36:00 - 06/05/03 13:05:00	2	30	491.65	488.28	3.37	0.7%	400	468.41	-68.41	-14.6%
11	06/05/03 13:16:00 - 06/05/03 13:45:00	2	30	491.22	488.56	2.66	0.5%	600	468.45	131.55	28.1%
12	06/05/03 13:56:00 - 06/05/03 14:25:00	2	30	494.16	488.23	5.93	1.2%	400	467.67	-67.67	-14.5%
13	06/05/03 14:46:00 - 06/05/03 15:15:00	2	30	495.13	492.24	2.89	0.6%	400	469.19	-69.19	-14.7%
14	06/05/03 15:26:00 - 06/05/03 15:55:00	2	30	494.58	491.94	2.64	0.5%	600	470.67	129.33	27.5%
15	06/05/03 16:06:00 - 06/05/03 16:35:00	2	30	494.16	491.00	3.16	0.6%	200	470.49		
16	06/05/03 16:46:00 - 06/05/03 17:15:00	2	30	495.91	491.04	4.87	1.0%	200	281.81	-81.81	-29.0%
17	06/05/03 17:26:00 - 06/05/03 17:55:00	2	30	494.57	492.47	2.1	0.4%	400	285.73	114.27	40.0%
18	06/05/03 18:05:00 - 06/05/03 18:34:00	2	30	495.66	491.32	4.34	0.9%	800	282.81		

<u>Turbine Power</u>. Turbine power measured by the CDH power meter (at the MDP) is 3.0 kW (5%) lower than the power measured by the SRI meter at the turbine. Part of this discrepancy is due to the voltage drop in the relatively long wiring run from the turbine to the MDP. The line losses are equivalent to 1.4 kW (see page A-20).

<u>Turbine Current</u>. Turbine current measured by the CDH meter is about 2 amps (3%) lower than the SRI meter.

<u>Turbine Gas Use</u>. The volume flow reading from the billing compensated billing meter is in good agreement (about 1%) with the Rosemont flow meter. The poor resolution of the gas meter means only comparisons are full load possible.

<u>Voltage</u>. The voltage measured at the MDP by SRI (using the gas compressor power meter) agrees within 1% with the CDH power meter. The SRI meter was located at the roof on the gas compressor while the CDH meter was located in the electrical room at the MDP (though voltage losses were small in this circuit).

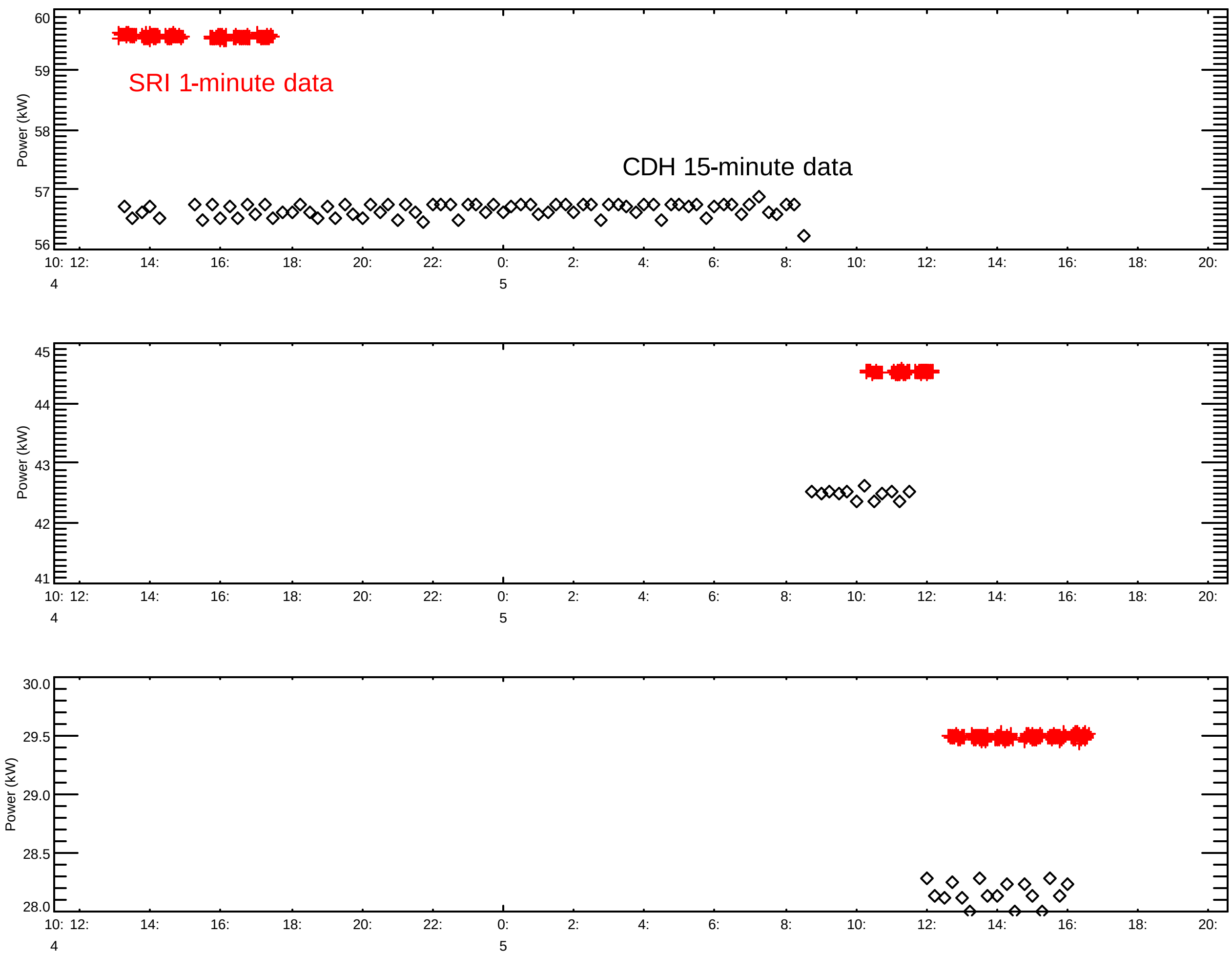


Figure A-7. Comparing CDH and SRI-Measured Microturbine Power Output

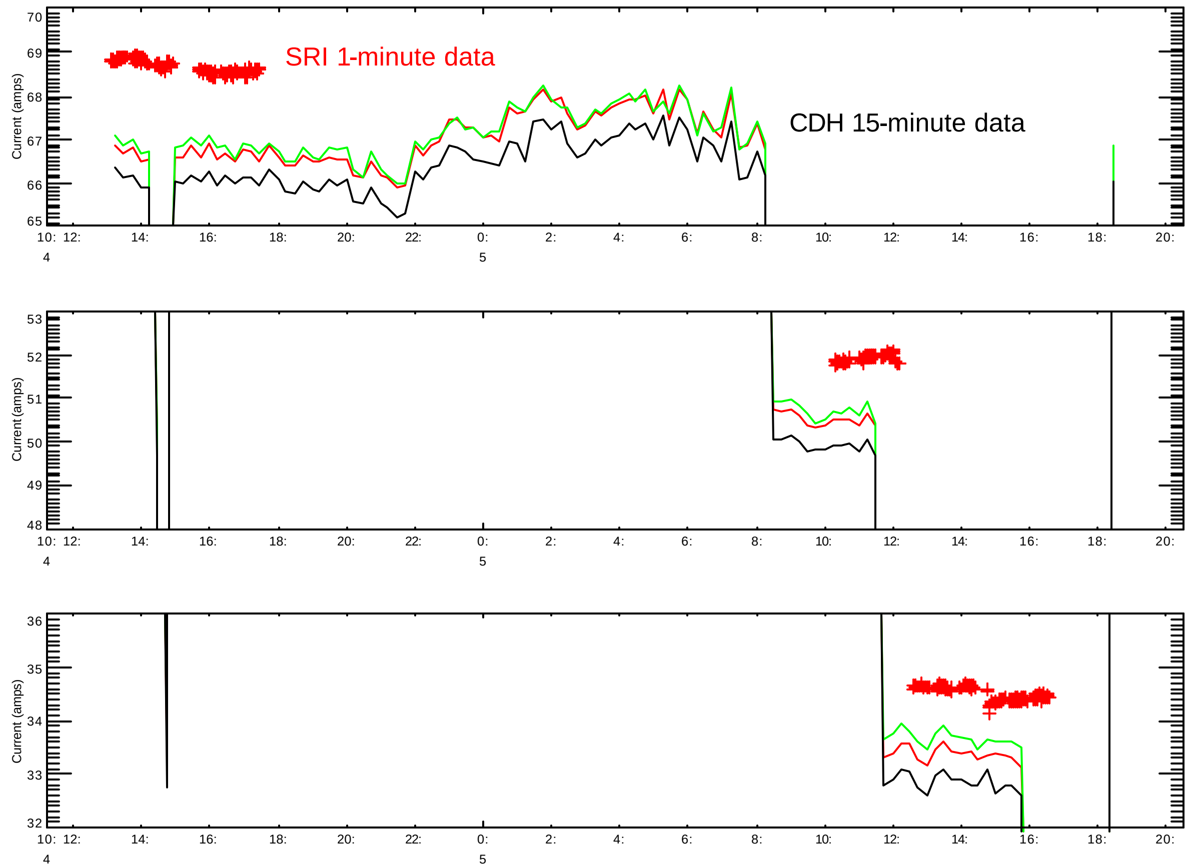


Figure A-8. Comparing CDH and SRI-Measured Microturbine Current

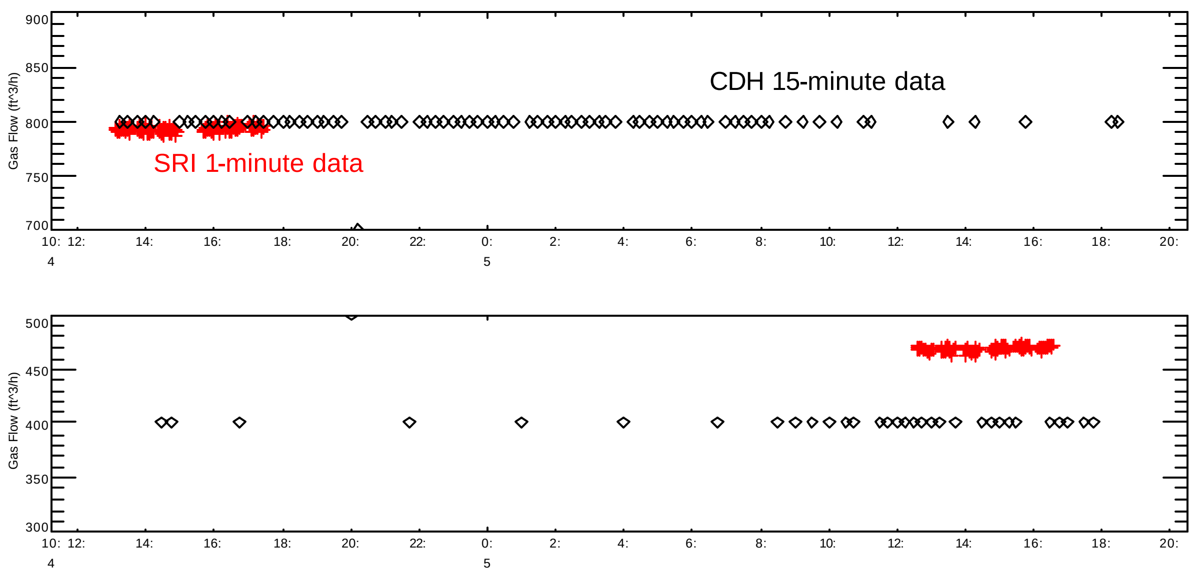


Figure A-9. Comparing Measured Microturbine Gas Input

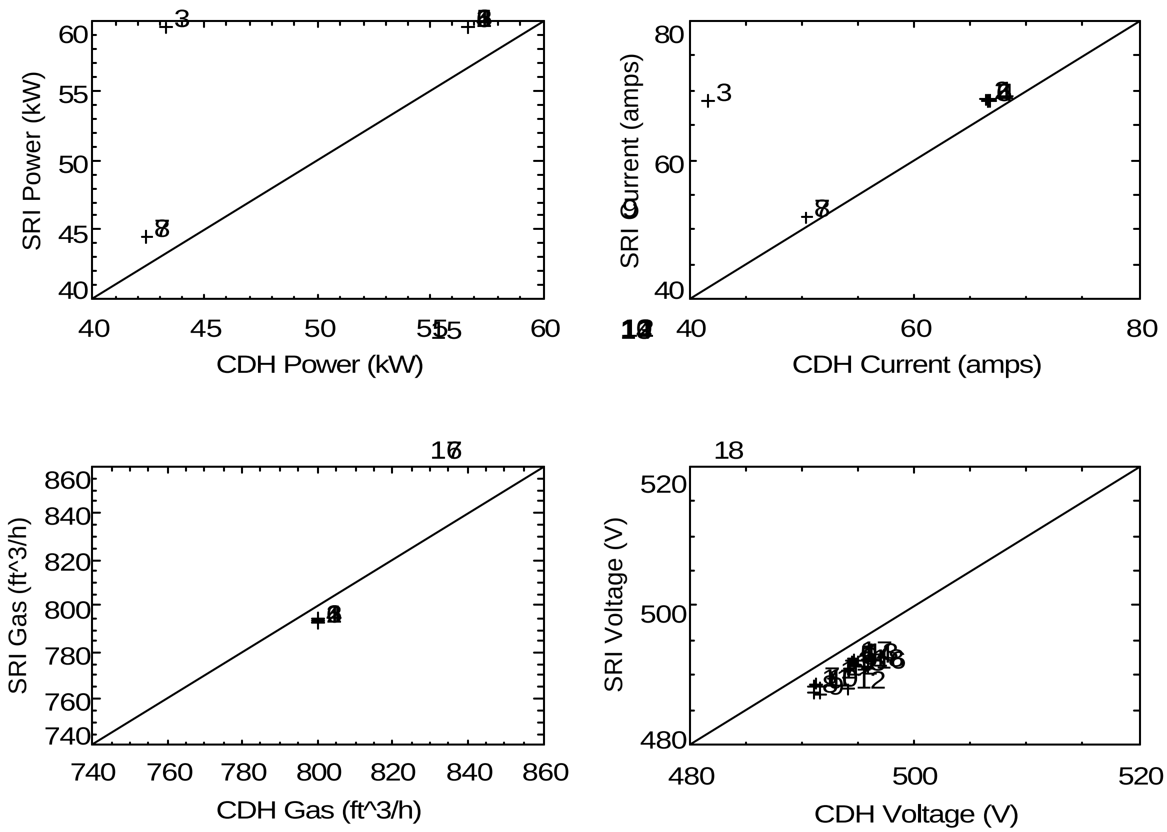


Figure A-10. Comparing Measured Data from CDH and SRI Meters (Each Point is an SRI Run)

VOLTAGE DROP IN TURBINE WIRING

The electric wiring between the microturbine and main distribution panel (MDP) is a 500-600 ft run of #1 wire. The plots below compare the voltage measured by the SRI power transducer at the turbine to the voltage measured at the gas compressor. Since the load on the gas compressor is small compared to the wire size, the voltage at the gas compressor is expected to be very close to the voltage at the MDP.

The turbine phase-to-phase voltage measured at the roof is 12 volts higher than the MDP voltage when the turbine supplying its rated output of 70 amps. Approximate readings with a handheld volt meter on June 4 confirmed a similar voltage drop from the MDP to the turbine (9 volts p-p).

The 12 volt drop in the wiring is equivalent to about 1.4 kW of power, since the current is the same at the turbine and MDP, but the voltage is lower.

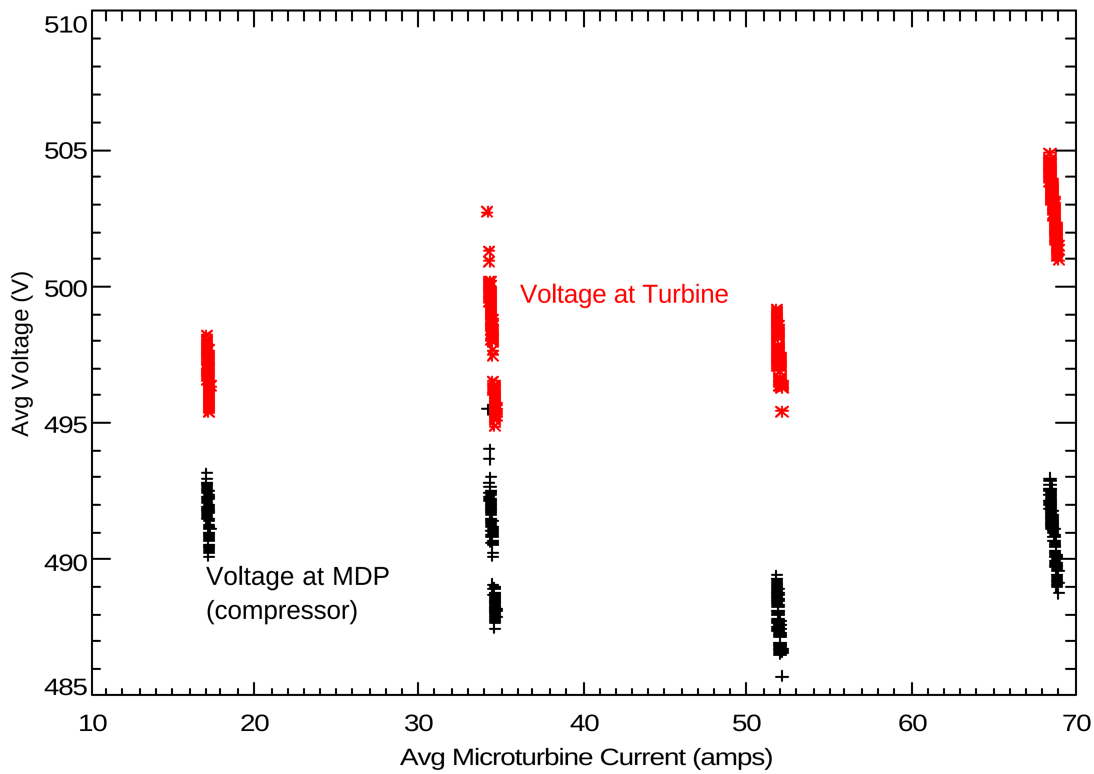
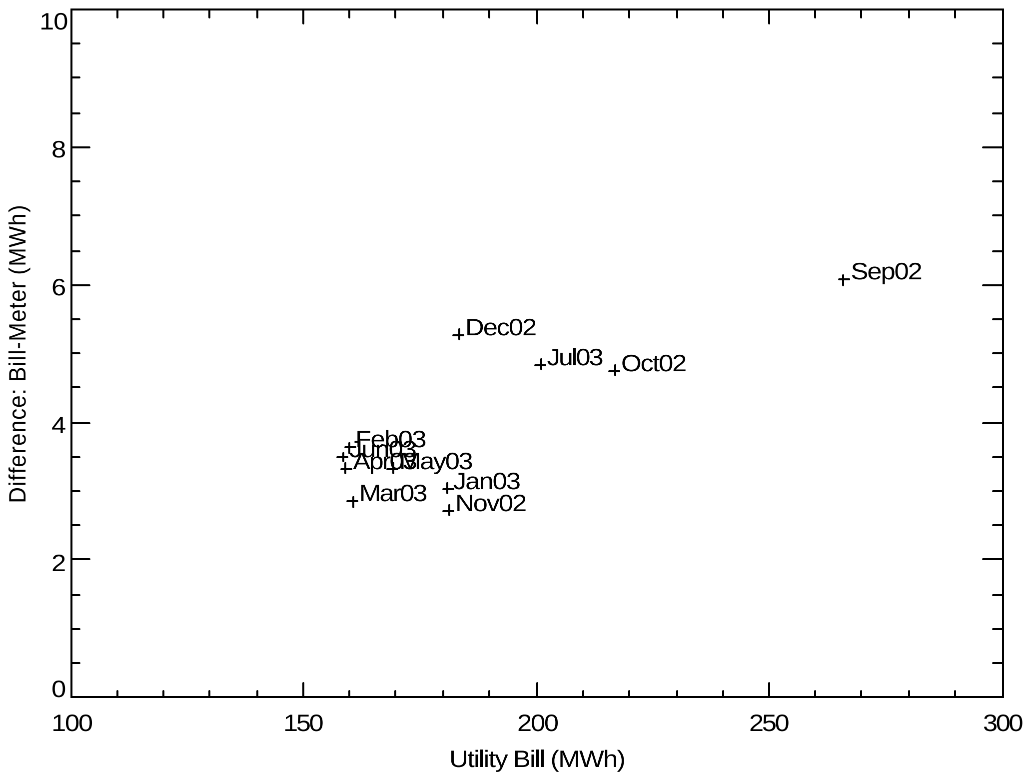
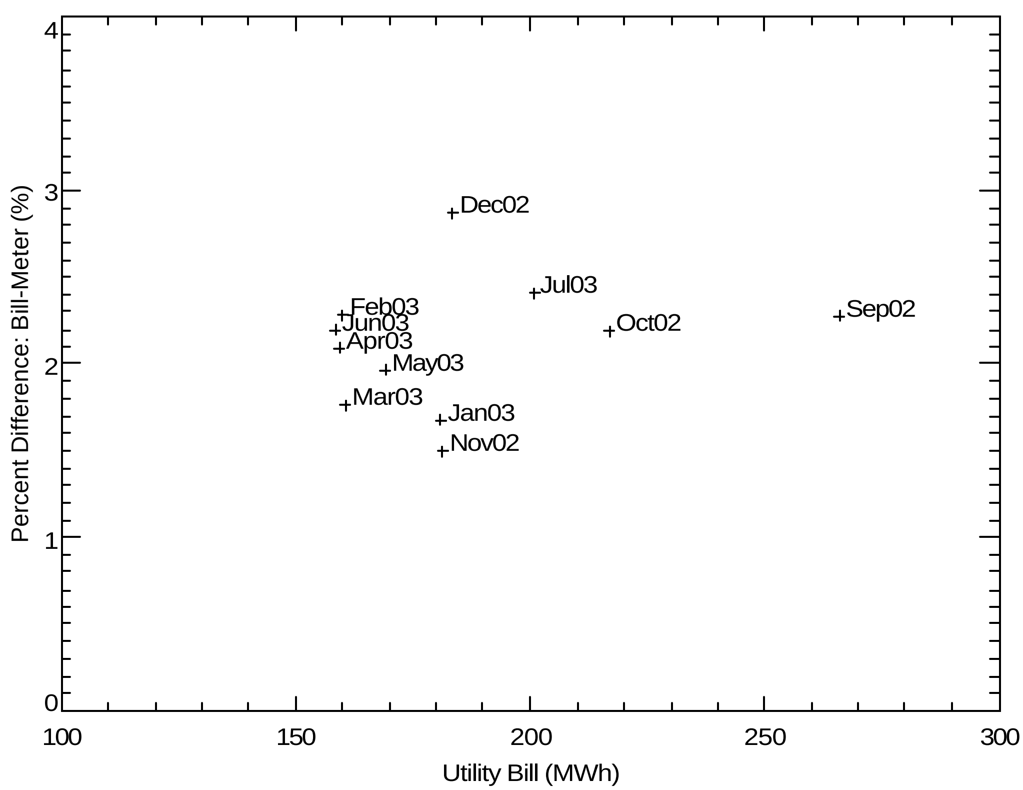


Figure A-11. Average Voltage Measured on Turbine and Gas Compressor Circuit

Comparing Veris Power Meters to LIPA Utility Bills at Waldbaums

The plots below provide a detailed comparison of the utility bill readings from LIPA and the power readings from the two Veris 8036-series power meters. The Veris data are proportionally scaled for missing data. The utility readings are assumed to occur at noon of the read date. The LIPA bills are consistently about 2% higher than the cumulative Veris readings.


Difference: Bill-Meter (MWh)
Utility Bill (MWh)
Sep02
Dec02
Jul03
Oct02
Feb03
Jun03
Apr03
May03
Jan03
Mar03
Nov02


Percent Difference: Bill-Meter (%)
Utility Bill (MWh)
Dec02
Jul03
Sep02
Feb03
Jun03
Oct02
Apr03
May03
Mar03
Jan03
Nov02

Check of TSI Before Calibration (April 8, 2003)

TSI CERTIFICATE OF CALIBRATION AND TESTING

TSI Model 8360 Serial No. 96110353

Description VELOCICALC PLUS PORTABLE AIR VELOCITY METER

Calibration Standard WIND TUNNEL CALIBRATION SYSTEM, SERIAL NO. 110

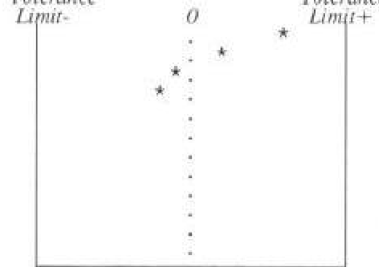
CALIBRATION VERIFICATION RESULTS

Calibration Standard	Instrument Output	Difference	
99.3 ft/min	101.1 ft/min	1.8%	PASS
198.2 ft/min	199.1 ft/min	0.5%	PASS
995.5 ft/min	991.8 ft/min	-0.4%	PASS
8026.9 ft/min	7980.2 ft/min	-0.6%	PASS

******* AS FOUND DATA *******
(INITIAL CALIBRATION CHECK)

32.0 °F	31.7 °F	-0.3 °F	PASS
140.0 °F	139.9 °F	-0.1 °F	PASS
-7.84 in.H2O	-7.82 in.H2O	+0.02	PASS
+7.94 in.H2O	+7.91 in.H2O	-0.03	PASS
28.9 %rh	28.5 %rh	-0.4 %rh	PASS
93.9 %rh	89.3 %rh	-4.6 %rh	FAIL

Error Compared to Tolerance



Tolerance Limits:
Velocity: ±3% of reading or 3 ft/min whichever is greater
Temperature: ±0.5 °F
Humidity: ±3.0%rh
Pressure: ±0.5% of reading ±0.01in.H2O

Velocity Calibration Conditions: Ambient Temp: 23.7°C Barometric Pressure: 745.9 mmHg

Velocity Corrected to Std Conditions of: Ambient Temp: 21.1°C Barometric Pressure: 760.0 mmHg

TSI does hereby certify that all materials, components, and workmanship used in the manufacture of this equipment are in strict accordance with the applicable specifications agreed upon by TSI and the customer and with all published specifications. All performance and acceptance tests required under this contract were successfully conducted according to required specifications. Furthermore, all test and calibration data supplied by TSI has been obtained using standards whose accuracies are traceable to the National Institute of Standards and Technology (NIST) or has been verified with respect to instrumentation whose accuracy is traceable to NIST, or is derived from accepted values of physical constants. Our Quality Management System complies with ISO 9001 requirements and calibration procedures for this instrument adhere to ISO 10012. The accuracy of the velocity calibration facilities is at least a ratio of 1:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the humidity calibration facilities is at least a ratio of 2:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the pressure calibration facilities is at least a ratio of 2.5:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the temperature calibration facilities is at least a ratio of 10:1 with respect to the accuracy specifications of the instrument being calibrated.

Applicable Test Report	Report Number	Date Last Verified	Date Due
DC voltage	8100026003	09-30-02	09-30-03
Barometric Pressure	E001329	05-10-02	05-10-03
Temperature (0°C)	77377	07-08-02	07-08-03
Temperature (19-35°C)	77370	07-08-02	07-08-03
Temperature (60°C)	77375	07-08-02	07-08-03
Pressure	E001517	02-28-03	02-28-04
Pressure	P04152002-02A	04-15-02	04-15-03
Velocity	836/264927	03-16-01	03-16-04
Dewpoint	266896-02	12-02-02	12-31-03

Calibrated by

☒ Final Function Check

Apr 08, 2003
Calibration Date

TSI Incorporated
Environmental Measurements and Controls Division

Mailing Address: P.O. Box 64394 St. Paul, MN 55164 USA
Shipping Address: 500 Cardigan Road Shoreview, MN 55126 USA
Phone: (800) 777-8356 or (651) 490-2711 **Fax:** (651) 490-2874

TSI After Calibration (April 9, 2003)

TSI CERTIFICATE OF CALIBRATION AND TESTING

TSI Model 8360 Serial No. 96110353

Description VELOCICALC PLUS PORTABLE AIR VELOCITY METER

Calibration Standard WIND TUNNEL CALIBRATION SYSTEM, SERIAL NO. 106

CALIBRATION VERIFICATION RESULTS

Calibration Standard	*Instrument Output*	*Difference*	
0.0 ft/min	0.0 ft/min		PASS
34.7 ft/min	35.0 ft/min	0.9%	PASS
65.6 ft/min	65.1 ft/min	-0.8%	PASS
100.3 ft/min	100.5 ft/min	0.2%	PASS
159.6 ft/min	158.6 ft/min	-0.6%	PASS
332.3 ft/min	330.7 ft/min	-0.5%	PASS
649.5 ft/min	644.9 ft/min	-0.7%	PASS
997.2 ft/min	997.7 ft/min	0.1%	PASS
1468.0 ft/min	1470.4 ft/min	0.2%	PASS
2509.7 ft/min	2506.3 ft/min	-0.1%	PASS
4519.5 ft/min	4513.0 ft/min	-0.1%	PASS
7984.1 ft/min	7974.0 ft/min	-0.1%	PASS
32.0 °F	31.7 °F	-0.3 °F	PASS
140.0 °F	139.9 °F	-0.1 °F	PASS
-7.84 in.H2O	-7.82 in.H2O	+0.02	PASS
+7.94 in.H2O	+7.91 in.H2O	-0.03	PASS
30.7 %rh	31.5 %rh	0.8 %rh	PASS
72.7 %rh	72.7 %rh	0.0 %rh	PASS

Error Compared to Tolerance — *Tolerance Limit-* / *0* / *Tolerance Limit+*

Tolerance Limits:
Velocity: ±3% of reading or 3 ft/min whichever is greater
Temperature: ±0.5 °F
Humidity: ±3.0%rh
Pressure: ±0.5% of reading ±0.01in.H2O

Velocity Calibration Conditions: Ambient Temp: 22.7°C Barometric Pressure: 743.0 mmHg

Velocity Corrected to Std Conditions of: Ambient Temp: 21.1°C Barometric Pressure: 760.0 mmHg

TSI does hereby certify that all materials, components, and workmanship used in the manufacture of this equipment are in strict accordance with the applicable specifications agreed upon by TSI and the customer and with all published specifications. All performance and acceptance tests required under this contract were successfully conducted according to required specifications. Furthermore, all test and calibration data supplied by TSI has been obtained using standards whose accuracies are traceable to the National Institute of Standards and Technology (NIST) or has been verified with respect to instrumentation whose accuracy is traceable to NIST, or is derived from accepted values of physical constants. Our Quality Management System complies with ISO 9001 requirements and calibration procedures for this instrument adhere to ISO 10012. The accuracy of the velocity calibration facilities is at least a ratio of 1:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the humidity calibration facilities is at least a ratio of 2:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the pressure calibration facilities is at least a ratio of 2.5:1 with respect to the accuracy specifications of the instrument being calibrated. The accuracy of the temperature calibration facilities is at least a ratio of 10:1 with respect to the accuracy specifications of the instrument being calibrated.

Applicable Test Report	Report Number	Date Last Verified	Date Due
DC voltage	8100026003	09-30-02	09-30-03
Barometric Pressure	E001329	05-10-02	05-10-03
Temperature (0°C)	77377	07-08-02	07-08-03
Temperature (19-35°C)	77370	07-08-02	07-08-03
Temperature (60°C)	77375	07-08-02	07-08-03
Pressure	E001517	02-28-03	02-28-04
Pressure	P04152002-02A	04-15-02	04-15-03
Velocity	836/264927	03-16-01	03-16-04
Dewpoint	266896-02	12-02-02	12-31-03

Calibrated by

☒ Final
Function Check

Apr 09, 2003
Calibration Date

TSI Incorporated
Environmental Measurements and Controls Division

Mailing Address: P.O. Box 64394 St. Paul, MN 55164 USA
Shipping Address: 500 Cardigan Road Shoreview, MN 55126 USA
Phone: (800) 777-8356 or (651) 490-2711 **Fax:** (651) 490-2874

APPENDIX B

MONTHLY TABLES
SUMMARIZING DAILY CHP EFFICIENCY

Table B-1. Microturbine Generation and CHP Performance – April 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Apr 18, 2003	747.3	9,859	54.1	12.3	1	0	24.0%	23.6%
Apr 19, 2003	1,360.2	17,806	95.1	21.9	605	0	24.2%	27.2%
Apr 20, 2003	1,360.1	18,007	94.7	21.6	1,965	0	24.0%	34.5%
Apr 21, 2003	1,359.4	17,806	94.5	21.6	2,980	0	24.2%	40.6%
Apr 22, 2003	1,359.2	18,007	94.1	21.5	3,250	0	24.0%	41.6%
Apr 23, 2003	647.5	8,450	43.6	9.9	1,834	0	24.4%	45.7%
Apr 24, 2003	896.3	11,066	58.3	13.0	392	0	25.8%	29.0%
Apr 25, 2003	1,360.2	17,907	94.2	21.8	139	0	24.1%	24.5%
Apr 26, 2003	1,360.3	17,907	94.1	21.8	162	0	24.1%	24.6%
Apr 27, 2003	835.8	18,108	93.6	21.3	460	0	14.0%	16.1%
Apr 28, 2003	1,360.4	18,410	93.8	21.1	1,363	0	23.5%	30.5%
Apr 29, 2003	1,349.1	18,309	93.7	21.1	1,186	0	23.4%	29.5%
Apr 30, 2003	1,359.9	18,007	93.8	21.2	1,826	0	24.0%	33.7%
Totals	***15,356***	***209,649***	***1,097***	***250***	***16,162***	***0***	***23.2%***	***30.5%***

Note: Actual natural gas HHV is used.

Table B-2. Microturbine Generation and CHP Performance – May 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
May 1, 2003	1,359.6	18,007	94.1	21.2	2,215	0	24.0%	35.9%
May 2, 2003	1,359.6	18,090	92.8	20.9	1,368	248	23.9%	32.4%
May 3, 2003	1,360.8	18,090	94.1	21.1	2,509	0	23.9%	37.4%
May 4, 2003	1,360.0	17,990	94.4	21.2	2,698	0	24.0%	38.6%
May 5, 2003	1,360.2	18,025	94.4	21.3	3,193	0	24.0%	41.3%
May 6, 2003	1,359.4	17,824	94.2	21.3	2,819	0	24.2%	39.6%
May 7, 2003	1,354.5	18,327	93.7	21.1	1,695	0	23.5%	32.3%
May 8, 2003	1,359.1	17,925	94.0	21.1	2,521	0	24.1%	37.7%
May 9, 2003	1,359.1	18,327	93.8	21.2	2,248	0	23.6%	35.4%
May 10, 2003	1,357.5	18,327	93.7	21.2	1,876	0	23.5%	33.4%
May 11, 2003	1,359.4	18,327	93.6	21.0	2,123	0	23.6%	34.8%
May 12, 2003	1,358.9	18,327	93.3	21.1	2,431	0	23.6%	36.4%
May 13, 2003	1,015.2	13,595	70.2	15.8	1,274	0	23.7%	32.7%
May 14, 2003	1,187.9	15,911	81.5	18.3	0	0	23.7%	23.3%
May 15, 2003	244.6	6,948	36.1	8.1	99	0		
May 16, 2003	5.9	0	0.0	0.0	0	0		
May 17, 2003	3.4	0	0.0	0.0	0	0		
May 18, 2003	3.5	0	0.0	0.0	1	0		
May 19, 2003	3.1	0	0.0	0.0	1	0		
May 20, 2003	4.4	0	0.0	0.0	1	0		
May 21, 2003	3.5	0	0.0	0.0	0	0		
May 22, 2003	4.1	0	0.0	0.0	0	0		
May 23, 2003	792.7	10,574	55.9	12.1	12	0	23.8%	23.5%
May 24, 2003	1,360.5	18,025	93.5	20.9	0	0	24.0%	23.6%
May 25, 2003	1,360.7	18,126	93.3	20.8	0	0	23.9%	23.5%
May 26, 2003	1,360.2	18,025	93.5	20.8	0	0	24.0%	23.6%
May 27, 2003	1,360.9	18,227	93.2	20.8	0	0	23.7%	23.3%
May 28, 2003	1,361.2	18,428	92.9	20.8	0	236	23.5%	24.4%
May 29, 2003	1,347.7	18,529	92.5	20.9	0	0	23.1%	22.7%
May 30, 2003	1,327.7	18,428	92.4	20.9	0	0	22.9%	22.5%
May 31, 2003	1,359.2	18,629	92.5	20.9	0	1,562	23.2%	31.2%
Totals	***30,414***	***411,031***	***2,113***	***475***	***29,084***	***2,045***	***23.5%***	***30.7%***

Note: Actual natural gas HHV is used.

Table B-3. Microturbine Generation and CHP Performance – June 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Jun 1, 2003	1,360.0	18,529	92.5	20.8	0	476	23.3%	25.5%
Jun 2, 2003	1,349.7	18,629	92.8	20.8	0	0	23.0%	22.6%
Jun 3, 2003	1,353.4	18,629	93.1	20.8	0	0	23.1%	22.7%
Jun 4, 2003	1,348.9	18,215	93.3	20.9			23.5%	
Jun 5, 2003	1,090.0	15,382	93.0	20.9			22.1%	
Jun 6, 2003	1,060.3	18,115	92.7	20.7	4	0	18.2%	17.9%
Jun 7, 2003	1,359.1	18,722	92.8	20.8	0	963	23.1%	27.8%
Jun 8, 2003	1,359.9	18,823	92.6	20.7	0	606	23.0%	25.8%
Jun 9, 2003	1,352.1	18,722	92.8	20.7	0	385	23.0%	24.6%
Jun 10, 2003	1,324.8	18,823	92.8	20.8	0	137	22.3%	22.7%
Jun 11, 2003	1,358.2	18,924	92.5	20.9	0	2,034	22.8%	33.2%
Jun 12, 2003	1,315.5	18,621	92.7	21.0	0	1,396	22.4%	29.5%
Jun 13, 2003	1,357.1	18,621	91.9	20.5	14	996	23.2%	28.2%
Jun 14, 2003	1,317.0	18,621	92.6	20.7	0	1,219	22.4%	28.6%
Jun 15, 2003	1,316.1	18,520	92.6	20.7	0	150	22.5%	23.0%
Jun 16, 2003	1,359.6	18,418	93.1	20.8	0	0	23.5%	23.1%
Jun 17, 2003	1,358.7	18,317	93.2	20.8	0	0	23.6%	23.2%
Jun 18, 2003	1,359.7	18,621	92.7	20.7	0	1,731	23.2%	32.1%
Jun 19, 2003	1,346.2	18,823	92.4	20.8	0	1,768	22.7%	31.7%
Jun 20, 2003	1,346.3	18,722	92.4	20.8	0	796	22.9%	26.7%
Jun 21, 2003	1,356.7	18,722	92.5	20.7	0	317	23.0%	24.4%
Jun 22, 2003	1,356.5	18,722	92.4	5.8	0	0	23.0%	22.9%
Jun 23, 2003	1,302.7	18,418	92.5	0.0	0	0	22.4%	22.4%
Jun 24, 2003	1,261.7	18,115	92.9	0.0	0	0	22.0%	22.0%
Jun 25, 2003	1,221.8	17,811	93.1	0.0	0	0	21.6%	21.6%
Jun 26, 2003	1,154.7	16,900	88.0	8.8	0	679	21.5%	25.4%
Jun 27, 2003	1,092.9	15,888	82.7	18.1	0	1,334	21.7%	29.7%
Jun 28, 2003	1,322.5	18,823	93.1	20.5	0	0	22.3%	21.9%
Jun 29, 2003	1,336.0	18,924	93.2	20.4	0	349	22.4%	23.9%
Jun 30, 2003	1,289.3	18,621	93.1	20.2	0	1,888	21.9%	31.7%
Totals	***39,087***	***549,741***	***2,767***	***530***	***18***	***17,223***	***22.5%***	***25.4%***

Note: Actual natural gas HHV is used.

Note: Heat Recovery and CHP Efficiency are not shown for June 4-5 due to Danfoss Controller malfunction.

Table B-4. Microturbine Generation and CHP Performance – July 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Jul 1, 2003	1,305.7	18,823	93.2	20.4	0	0	22.0%	21.6%
Jul 2, 2003	1,270.6	18,216	91.4	19.6	0	1,422	22.1%	29.5%
Jul 3, 2003	1,360.3	19,209	92.7	20.5	0	2,064	22.5%	32.9%
Jul 4, 2003	1,271.9	18,501	93.0	20.3	0	3,580	21.7%	40.7%
Jul 5, 2003	1,178.8	17,693	93.5	20.2	0	4,225	20.9%	44.4%
Jul 6, 2003	1,191.5	17,794	93.3	20.2	0	3,921	21.1%	42.7%
Jul 7, 2003	1,256.3	18,227	93.1	20.3	0	3,731	21.8%	41.9%
Jul 8, 2003	1,170.2	17,119	89.9	19.4	103	3,971	21.5%	44.9%
Jul 9, 2003	1,306.3	18,629	92.8	20.8	0	2,279	22.2%	34.1%
Jul 10, 2003	1,349.2	19,234	92.6	20.7	0	1,071	22.3%	27.5%
Jul 11, 2003	1,301.3	18,529	92.5	20.6	0	3,839	22.3%	42.6%
Jul 12, 2003	1,252.6	18,327	93.0	20.7	0	2,559	21.6%	35.2%
Jul 13, 2003	1,264.3	18,327	93.1	20.5	0	539	21.8%	24.4%
Jul 14, 2003	1,330.4	18,957	93.1	20.9			22.3%	
Jul 15, 2003	1,309.8	18,806	93.1	21.1			22.1%	
Jul 16, 2003	1,281.7	18,428	92.9	21.1			22.0%	
Jul 17, 2003	1,258.7	18,428	93.1	21.0			21.6%	
Jul 18, 2003	1,254.8	18,227	93.1	20.8			21.8%	
Jul 19, 2003	1,269.3	18,428	92.9	20.5	0	442	21.8%	23.8%
Jul 20, 2003	1,268.1	18,428	93.1	20.5	0	1,018	21.8%	26.9%
Jul 21, 2003	1,274.4	18,428	92.9	20.5	0	4,695	21.9%	47.0%
Jul 22, 2003	1,248.5	18,126	92.8	20.5	0	4,764	21.8%	47.7%
Jul 23, 2003	1,247.8	18,126	92.8	20.5	0	4,887	21.7%	48.3%
Jul 24, 2003	1,243.0	18,126	93.0	20.5	0	4,639	21.7%	46.9%
Jul 25, 2003	1,223.4	18,126	93.4	20.5	0	2,288	21.3%	33.5%
Jul 26, 2003	1,218.1	18,025	93.5	20.6	0	3,368	21.3%	39.6%
Jul 27, 2003	1,179.2	17,623	93.3	20.5	0	4,210	21.0%	44.5%
Jul 28, 2003	1,209.6	17,824	92.8	20.5	0	3,507	21.4%	40.7%
Jul 29, 2003	1,276.9	18,529	92.7	20.5	0	1,400	21.8%	29.0%
Jul 30, 2003	1,304.0	18,730	93.0	20.5	0	2,046	22.1%	32.6%
Jul 31, 2003	1,307.9	18,730	93.0	20.6	0	1,636	22.1%	30.5%
Totals	***39,185***	***568,723***	***2,878***	***636***	***103***	***72,102***	***21.8%***	***34.1%***

Note: Actual natural gas HHV is used.

Note: Heat Recovery and CHP Efficiency are not shown for July 14-18 due to Danfoss Controller malfunction.

Table B-5. Microturbine Generation and CHP Performance – August 2003

Date	[1] Turbine: Power Output (kWh)	[2] Turbine: Gas Input (MBTU)	[3] Parasitic Loads: Gas Compressor (kWh)	[4] Parasitic Loads: Heat Recovery Glycol Pump (kWh)	[5] Heat Recovered: Space Heating (MBTU)	[6] Heat Recovered: Desiccant Regen (MBTU)	[7] = [1-3] / [2] "Net" Turbine Generation Efficiency (%)	[8] = [1-3-4+5+6] / [2] "Net" CHP Efficiency (%)
Aug 1, 2003	1,265.9	18,428	92.9	20.6	0	4,868	21.7%	47.8%
Aug 2, 2003	1,221.1	18,025	93.1	20.6	0	5,310	21.4%	50.4%
Aug 3, 2003	1,223.8	18,025	93.2	20.6	0	5,308	21.4%	50.5%
Aug 4, 2003	1,220.1	17,925	93.0	20.5	0	5,358	21.5%	51.0%
Aug 5, 2003	1,222.1	17,937	92.7	20.6	0	5,434	21.5%	51.4%
Aug 6, 2003	1,210.8	17,836	92.8	20.6	0	4,791	21.4%	47.9%
Aug 7, 2003	1,205.5	17,735	92.8	20.6	0	4,649	21.4%	47.2%
Aug 8, 2003	1,213.4	17,936	92.8	20.6	0	5,193	21.3%	49.9%
Aug 9, 2003	1,222.1	17,936	93.0	20.5	0	5,083	21.5%	49.4%
Aug 10, 2003	22.5	100	1.8	0.4	0	39		
Aug 11, 2003	2.2	0	0.4	0.0	0	0		
Aug 12, 2003	2.1	0	0.1	0.0	0	0		
Aug 13, 2003	1.8	0	0.0	0.0	0	0		
Aug 14, 2003	-99.0	0	0.0	0.0	0	0		
Aug 15, 2003	-96.7	0	0.4	0.0	0	0		
Aug 16, 2003	1.9	0	0.0	0.0	0	0		
Aug 17, 2003	0.5	0	0.0	0.0	0	0		
Aug 18, 2003	1.6	0	0.0	0.0	0	0		
Aug 19, 2003	1.9	0	0.0	0.0	0	0		
Aug 20, 2003	2.2	0	0.0	0.0	0	0		
Aug 21, 2003	2.4	0	0.0	0.0	0	0		
Aug 22, 2003	2.0	0	0.0	0.0	0	0		
Aug 23, 2003	0.7	0	0.0	0.0	0	0		
Aug 24, 2003	0.6	0	0.0	0.0	0	0		
Aug 25, 2003	2.0	0	0.0	0.0	0	0		
Aug 26, 2003	1.9	0	0.0	0.0	0	0		
Aug 27, 2003	2.4	0	0.0	0.0	0	0		
Aug 28, 2003	1.5	0	0.0	0.0	0	0		
Aug 29, 2003	1.8	0	0.0	0.0	0	0		
Aug 30, 2003	1.6	0	0.0	0.0	0	0		
Aug 31, 2003	0.9	0	0.0	0.0	0	0		
Totals	***10,864***	***161,883***	***839***	***186***	***0***	***46,035***	***21.1%***	***49.2%***

Note: Actual natural gas HHV is used.

Table B-6. Microturbine Generation and CHP Performance – September 2003

Date	[1] Turbine: Power Output (kWh)	[2] Turbine: Gas Input (MBTU)	[3] Parasitic Loads: Gas Compressor (kWh)	[4] Parasitic Loads: Heat Recovery Glycol Pump (kWh)	[5] Heat Recovered: Space Heating (MBTU)	[6] Heat Recovered: Desiccant Regen (MBTU)	[7] = [1-3] / [2] "Net" Turbine Generation Efficiency (%)	[8] = [1-3-4+5+6] / [2] "Net" CHP Efficiency (%)
Sep 1, 2003	1.1	0	0.0	0.0	0	0		
Sep 2, 2003	1.3	0	0.0	0.0	0	0		
Sep 3, 2003	1.6	0	0.0	0.0	0	0		
Sep 4, 2003	1.2	0	0.0	0.0	0	0		
Sep 5, 2003	0.8	0	0.0	0.0	0	0		
Sep 6, 2003	0.8	0	0.0	0.0	0	0		
Sep 7, 2003	0.3	0	0.0	0.0	0	0		
Sep 8, 2003	1.6	100	0.8	0.0	0	0		
Sep 9, 2003	1.2	0	0.0	0.0	0	0		
Sep 10, 2003	1.9	0	1.1	0.1	0	0		
Sep 11, 2003	548.3	7,916	39.8	8.6	0	792	21.9%	31.6%
Sep 12, 2003	257.8	15,731	77.3	17.2	13	672		
Sep 13, 2003	920.2	13,627	66.2	14.6	67	3,578	21.4%	47.8%
Sep 14, 2003	1,333.3	18,838	93.2	20.5	0	4,890	22.5%	48.1%
Sep 15, 2003	1,330.7	18,838	92.8	20.5	0	4,097	22.4%	43.8%
Sep 16, 2003	1,308.8	18,637	92.8	20.4	0	1,195	22.3%	28.3%
Sep 17, 2003	1,337.6	18,036	88.7	19.5	0	544	23.6%	26.3%
Sep 18, 2003	1,365.1	19,138	92.9	20.5	0	331	22.7%	24.1%
Sep 19, 2003	1,306.2	18,637	92.9	20.4	0	4,743	22.2%	47.3%
Sep 20, 2003	1,271.0	18,437	93.0	20.4	0	3,358	21.8%	39.6%
Sep 21, 2003	1,324.4	18,838	93.0	20.5	0	56	22.3%	22.2%
Sep 22, 2003	1,348.4	19,038	92.9	20.5	0	1,613	22.5%	30.6%
Sep 23, 2003	1,295.4	18,537	92.3	20.6	0	3,091	22.2%	38.4%
Sep 24, 2003	1,325.9	18,737	92.7	20.6	175	0	22.5%	23.0%
Sep 25, 2003	1,300.4	18,737	92.5	20.6	0	2,871	22.0%	36.9%
Sep 26, 2003	1,300.4	18,737	92.7	20.5	0	2,027	22.0%	32.4%
Sep 27, 2003	1,280.5	18,437	92.7	20.5	0	4,027	22.0%	43.4%
Sep 28, 2003	1,291.7	18,537	92.3	20.4	0	2,841	22.1%	37.0%
Sep 29, 2003	752.2	11,222	55.1	12.1	203	111	21.2%	23.6%
Sep 30, 2003	0.3	0	0.0	0.0	0	0		
Totals	***22,210***	***328,755***	***1,627***	***359***	***457***	***40,837***	***21.4%***	***33.6%***

Note: Actual natural gas HHV is used.

Table B-7. Microturbine Generation and CHP Performance – October 2003

	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Oct 1, 2003	0.3	0	0.0	0.0	0	0		
Oct 2, 2003	527.4	6,713	35.2	7.6	623	0	25.0%	33.9%
Oct 3, 2003	1,374.1	18,637	93.5	20.7	1,673	0	23.5%	32.1%
Oct 4, 2003	1,365.1	18,838	92.9	20.7	1,110	0	23.0%	28.6%
Oct 5, 2003	1,371.4	18,838	93.0	20.7	1,443	0	23.2%	30.4%
Oct 6, 2003	1,373.9	18,838	93.3	20.8	1,576	0	23.2%	31.2%
Oct 7, 2003	1,369.3	18,838	93.3	20.8	1,178	0	23.1%	29.0%
Oct 8, 2003	1,339.0	18,737	93.1	20.6	352	1,633	22.7%	32.9%
Oct 9, 2003	649.4	9,719	47.6	10.5	237	265	21.1%	25.9%
Oct 10, 2003	294.6	3,607	20.7	4.2	0	124	25.9%	29.0%
Oct 11, 2003	1,359.9	18,938	92.9	20.7	399	0	22.8%	24.6%
Oct 12, 2003	1,363.3	18,938	92.7	20.7	487	415	22.9%	27.3%
Oct 13, 2003	1,341.8	18,737	92.7	20.6	342	133	22.8%	24.9%
Oct 14, 2003	1,361.0	18,938	92.6	20.6	451	439	22.9%	27.2%
Oct 15, 2003	1,343.9	18,838	92.2	20.6	429	410	22.7%	26.8%
Oct 16, 2003	1,362.8	18,938	92.9	20.7	1,075	0	22.9%	28.2%
Oct 17, 2003	257.7	4,108	20.4	4.5	151	0	19.7%	23.0%
Oct 18, 2003	0.3	200	0.8	0.2	0	0		
Oct 19, 2003	1.1	0	0.0	0.0	0	0		
Oct 20, 2003	826.1	10,721	53.5	11.9	300	0	24.6%	27.0%
Oct 21, 2003	1,322.8	18,737	92.3	20.5	0	975	22.4%	27.2%
Oct 22, 2003	1,374.0	18,637	92.7	20.6	1,389	138	23.5%	31.3%
Oct 23, 2003	1,373.5	18,337	93.0	20.7	2,448	0	23.8%	36.8%
Oct 24, 2003	1,373.5	18,236	93.6	20.6	1,900	0	24.0%	34.0%
Oct 25, 2003	1,373.9	18,537	93.9	20.7	1,224	0	23.6%	29.8%
Oct 26, 2003	1,259.5	18,337	89.3	19.6	67	3,661	21.8%	41.7%
Oct 27, 2003	1,349.1	18,938	92.6	20.4	0	3,206	22.6%	39.2%
Oct 28, 2003	1,359.3	18,737	93.0	20.6	592	0	23.1%	25.9%
Oct 29, 2003	1,365.2	18,737	92.6	20.6	269	1,152	23.2%	30.4%
Oct 30, 2003	1,372.5	18,838	93.4	20.6	823	0	23.2%	27.2%
Oct 31, 2003	1,371.6	18,737	93.4	20.6	525	278	23.3%	27.2%
Totals	***33,777***	***465,929***	***2,312***	***512***	***21,063***	***12,828***	***23.0%***	***29.9%***

Note: Actual natural gas HHV is used.

Table B-8. Microturbine Generation and CHP Performance – November 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Nov 1, 2003	1,350.4	18,737	93.1	20.6	338	909	22.9%	29.2%
Nov 2, 2003	1,362.4	18,938	93.1	20.5	0	287	22.9%	24.0%
Nov 3, 2003	1,331.6	18,637	93.0	20.5	0	2,387	22.7%	35.1%
Nov 4, 2003	1,370.4	18,737	93.3	20.7	666	684	23.3%	30.1%
Nov 5, 2003	1,094.5	16,232	81.1	18.0	425	1,102	21.3%	30.3%
Nov 6, 2003	0.0	0	0.0	0.0	0	0		
Nov 7, 2003	0.0	0	0.0	0.0	0	0		
Nov 8, 2003	0.0	0	0.0	0.0	0	0		
Nov 9, 2003	0.0	0	0.0	0.0	0	0		
Nov 10, 2003	490.0	5,110	27.7	6.1	1,052	0	30.9%	51.1%
Nov 11, 2003	1,373.6	18,437	93.4	20.8	2,273	0	23.7%	35.6%
Nov 12, 2003	1,374.0	18,737	92.8	20.7	1,078	636	23.3%	32.1%
Nov 13, 2003	255.4	4,910	23.8	5.3	106	186	16.1%	21.7%
Nov 14, 2003	0.0	0	0.3	0.0	0	0		
Nov 15, 2003	0.0	0	0.0	0.0	0	0		
Nov 16, 2003	0.0	0	0.0	0.0	0	0		
Nov 17, 2003	0.0	0	0.0	0.0	0	0		
Nov 18, 2003	2.6	100	2.5	0.1	0	0	0.4%	0.0%
Nov 19, 2003	0.0	0	0.0	0.0	0	0		
Nov 20, 2003	0.0	0	0.0	0.0	0	0		
Nov 21, 2003	0.0	0	0.0	0.0	0	0		
Nov 22, 2003	0.0	0	0.0	0.0	0	0		
Nov 23, 2003	0.0	0	0.0	0.0	0	0		
Nov 24, 2003	0.0	0	0.0	0.0	0	0		
Nov 25, 2003	0.0	0	0.0	0.0	0	0		
Nov 26, 2003	0.0	0	0.0	0.0	0	0		
Nov 27, 2003	0.0	0	0.0	0.0	0	0		
Nov 28, 2003	0.0	0	0.0	0.0	0	0		
Nov 29, 2003	0.0	0	0.0	0.0	0	0		
Nov 30, 2003	0.0	0	0.0	0.0	0	0		
Totals	***10,005***	***138,575***	***694***	***153***	***5,939***	***6,192***	***22.9%***	***31.3%***

Note: Actual natural gas HHV is used.

Table B-9. Microturbine Generation and CHP Performance – December 2003

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Dec 1, 2003	0.0	0	0.0	0.0	0	0		
Dec 2, 2003	0.0	0	0.0	0.0	0	0		
Dec 3, 2003	0.0	0	0.0	0.0	0	0		
Dec 4, 2003	621.1	8,417	47.9	10.4	1,578	0	23.2%	41.6%
Dec 5, 2003	1,188.0	13,727	77.4	17.0	3,110	0	27.6%	49.8%
Dec 6, 2003	0.0	0	0.0	0.0	0	0		
Dec 7, 2003	0.0	0	0.0	0.0	0	0		
Dec 8, 2003	0.0	0	0.0	0.0	0	0		
Dec 9, 2003	0.0	0	0.5	0.0	0	0		
Dec 10, 2003	0.0	0	0.0	0.0	0	0		
Dec 11, 2003	0.0	0	0.0	0.0	0	0		
Dec 12, 2003	0.0	0	0.0	0.0	0	0		
Dec 13, 2003	0.0	0	0.0	0.0	0	0		
Dec 14, 2003	0.0	0	0.0	0.0	0	0		
Dec 15, 2003	0.0	0	0.7	0.1	0	0		
Dec 16, 2003	0.0	0	0.0	0.0	0	0		
Dec 17, 2003	0.0	0	0.0	0.0	0	0		
Dec 18, 2003	0.0	0	0.0	0.0	0	0		
Dec 19, 2003	2.1	100	0.9	0.1	0	0	4.1%	4.3%
Dec 20, 2003	0.0	0	0.0	0.0	0	0		
Dec 21, 2003	0.0	0	0.0	0.0	0	0		
Dec 22, 2003	0.0	0	0.0	0.0	0	0		
Dec 23, 2003	0.0	0	1.5	0.1	0	0		
Dec 24, 2003	0.0	0	0.0	0.0	0	0		
Dec 25, 2003	0.0	0	0.0	0.0	0	0		
Dec 26, 2003	0.0	0	0.0	0.0	0	0		
Dec 27, 2003	0.0	0	0.0	0.0	0	0		
Dec 28, 2003	0.0	0	0.0	0.0	0	0		
Dec 29, 2003	732.9	10,120	54.5	12.1	0	0	22.9%	22.5%
Dec 30, 2003	1,372.5	17,335	93.4	21.0	0	0	25.2%	24.8%
Dec 31, 2003	1,372.9	17,134	94.1	21.0	0	0	25.5%	25.1%
Totals	***5,290***	***66,833***	***371***	***82***	***4,688***	***0***	***25.1%***	***31.7%***

Note: Actual natural gas HHV is used.

Table B-10. Microturbine Generation and CHP Performance – January 2004

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] =
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Jan 1, 2004	1,372.6	17,134	94.1	21.1	0	0	25.5%	25.0%
Jan 2, 2004	1,372.0	17,134	93.9	21.1	0	0	25.5%	25.0%
Jan 3, 2004	1,372.3	17,435	93.4	21.1	0	0	25.0%	24.6%
Jan 4, 2004	1,372.6	17,435	93.3	20.9	0	0	25.0%	24.6%
Jan 5, 2004	1,366.2	16,934	93.7	21.0	0	0	25.6%	25.2%
Jan 6, 2004	1,371.8	16,934	93.9	21.0	0	0	25.8%	25.3%
Jan 7, 2004	1,370.8	16,533	94.9	21.1	0	0	26.3%	25.9%
Jan 8, 2004	1,371.4	16,633	94.9	21.0	0	0	26.2%	25.8%
Jan 9, 2004	1,371.1	16,232	95.4	21.2	0	0	26.8%	26.4%
Jan 10, 2004	1,371.0	15,731	96.1	21.4	0	0	27.7%	27.2%
Jan 11, 2004	1,370.0	16,232	95.6	21.2	0	0	26.8%	26.4%
Jan 12, 2004	1,371.1	16,733	94.2	21.0	0	0	26.0%	25.6%
Jan 13, 2004	1,371.6	16,834	93.8	21.2	0	0	25.9%	25.5%
Jan 14, 2004	1,371.3	15,932	95.3	21.1	0	0	27.3%	26.9%
Jan 15, 2004	1,371.3	15,832	94.9	21.2	0	0	27.5%	27.1%
Jan 16, 2004	1,371.7	15,832	94.7	21.1	0	0	27.5%	27.1%
Jan 17, 2004	1,371.9	16,533	94.3	21.1	0	0	26.4%	25.9%
Jan 18, 2004	1,371.9	16,733	93.4	21.0	0	0	26.1%	25.6%
Jan 19, 2004	1,372.6	16,333	93.8	21.1	0	0	26.7%	26.3%
Jan 20, 2004	821.2	9,820	60.2	13.2	0	0	26.4%	26.0%
Jan 21, 2004	0.0	0	0.0	0.0	0	0		
Jan 22, 2004	780.8	9,619	53.7	12.1	0	0	25.8%	25.4%
Jan 23, 2004	1,371.0	16,032	94.5	21.3	0	0	27.2%	26.7%
Jan 24, 2004	1,371.1	16,132	94.7	21.3	0	0	27.0%	26.6%
Jan 25, 2004	1,370.6	15,832	95.5	21.3	0	0	27.5%	27.0%
Jan 26, 2004	1,371.1	16,132	95.3	21.3	0	0	27.0%	26.5%
Jan 27, 2004	1,296.1	15,331	89.6	20.1	1,866	0	26.9%	38.6%
Jan 28, 2004	264.4	3,106	17.9	3.9	904	0	27.1%	55.8%
Jan 29, 2004	0.0	0	0.0	0.0	0	0		
Jan 30, 2004	0.0	0	0.0	0.0	0	0		
Jan 31, 2004	0.0	0	0.0	0.0	0	0		
Totals	***34,702***	***417,133***	***2,394***	***535***	***2,769***	***0***	***26.4%***	***26.7%***

Note: Actual natural gas HHV is used.

Table B-11. Microturbine Generation and CHP Performance – February 2004

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] =
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Feb 1, 2004	0.0	0	0.0	0.0	0	0		
Feb 2, 2004	0.0	0	0.0	0.0	0	0		
Feb 3, 2004	0.0	0	0.0	0.0	0	0		
Feb 4, 2004	0.0	0	0.0	0.0	0	0		
Feb 5, 2004	0.0	0	0.0	0.0	0	0		
Feb 6, 2004	0.0	0	0.0	0.0	0	0		
Feb 7, 2004	0.0	0	0.0	0.0	0	0		
Feb 8, 2004	0.0	0	0.0	0.0	0	0		
Feb 9, 2004	503.6	6,313	35.7	7.9	1,496	0	25.3%	48.6%
Feb 10, 2004	1,366.0	16,959	93.5	20.8	3,881	0	25.6%	48.1%
Feb 11, 2004	1,365.4	16,809	93.8	20.9	4,573	0	25.8%	52.6%
Feb 12, 2004	1,365.6	16,533	94.5	21.0	5,067	0	26.2%	56.5%
Feb 13, 2004	1,365.6	16,834	93.7	20.9	4,462	0	25.8%	51.9%
Feb 14, 2004	1,365.5	16,934	93.5	21.1	4,416	0	25.6%	51.3%
Feb 15, 2004	1,365.3	16,433	94.5	21.2	5,474	0	26.4%	59.3%
Feb 16, 2004	1,364.9	16,232	95.4	21.2	5,607	0	26.7%	60.8%
Feb 17, 2004	1,326.5	16,032	92.6	20.5	5,198	0	26.3%	58.3%
Feb 18, 2004	1,296.7	15,932	89.4	20.0	4,420	0	25.9%	53.2%
Feb 19, 2004	1,361.7	16,733	93.2	21.0	4,536	0	25.9%	52.6%
Feb 20, 2004	1,365.2	16,934	93.5	21.0	4,466	0	25.6%	51.6%
Feb 21, 2004	1,365.7	17,134	92.6	21.0	4,227	0	25.4%	49.6%
Feb 22, 2004	1,365.3	16,934	93.2	21.0	4,198	0	25.6%	50.0%
Feb 23, 2004	1,365.3	16,934	93.8	21.1	4,427	0	25.6%	51.3%
Feb 24, 2004	1,364.9	16,733	93.7	21.0	4,766	0	25.9%	54.0%
Feb 25, 2004	1,364.9	16,733	93.8	21.1	4,918	0	25.9%	54.9%
Feb 26, 2004	1,365.3	16,834	93.9	21.0	4,487	0	25.8%	52.0%
Feb 27, 2004	1,365.3	16,834	93.9	20.9	4,314	0	25.8%	51.0%
Feb 28, 2004	1,365.7	17,134	93.5	20.9	3,761	0	25.3%	46.9%
Feb 29, 2004	1,366.7	17,435	93.2	20.9	3,532	0	24.9%	44.8%
Totals	***27,701***	***341,383***	***1,905***	***426***	***92,226***	***0***	***25.8%***	***52.4%***

Note: Actual natural gas HHV is used.

Table B-12. Microturbine Generation and CHP Performance – March 2004

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] =
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Mar 1, 2004	1,366.1	17,335	93.2	20.9	3,063	0	25.1%	42.3%
Mar 2, 2004	1,365.7	17,335	93.0	20.9	3,303	0	25.1%	43.7%
Mar 3, 2004	1,365.9	17,435	93.0	20.9	3,042	0	24.9%	42.0%
Mar 4, 2004	1,365.7	17,234	93.3	20.9	3,738	0	25.2%	46.5%
Mar 5, 2004	1,365.3	17,134	93.2	21.0	3,616	0	25.3%	46.0%
Mar 6, 2004	1,366.0	17,535	92.4	20.8	3,205	0	24.8%	42.7%
Mar 7, 2004	1,365.0	17,134	92.9	20.8	3,444	0	25.3%	45.0%
Mar 8, 2004	1,365.1	17,034	93.2	21.0	4,321	0	25.5%	50.4%
Mar 9, 2004	1,360.9	16,834	93.6	21.0	4,633	0	25.7%	52.8%
Mar 10, 2004	1,365.3	16,934	93.7	21.0	4,194	0	25.6%	50.0%
Mar 11, 2004	1,365.3	17,234	93.0	20.9	3,752	0	25.2%	46.6%
Mar 12, 2004	1,364.9	17,134	92.9	20.9	4,022	0	25.3%	48.4%
Mar 13, 2004	1,365.4	16,834	93.6	21.1	4,385	0	25.8%	51.4%
Mar 14, 2004	1,365.2	16,934	94.0	21.1	4,719	0	25.6%	53.1%
Mar 15, 2004	1,365.5	17,535	93.0	20.9	3,278	0	24.8%	43.1%
Mar 16, 2004	1,364.7	16,733	93.7	21.1	4,567	0	25.9%	52.8%
Mar 17, 2004	1,308.7	15,932	90.1	20.3	4,814	0	26.1%	55.9%
Mar 18, 2004	1,365.3	16,733	93.8	21.1	4,628	0	25.9%	53.2%
Mar 19, 2004	1,365.0	16,934	94.0	21.1	4,559	0	25.6%	52.1%
Mar 20, 2004	1,366.0	16,934	93.9	21.1	4,710	0	25.6%	53.0%
Mar 21, 2004	1,365.6	17,234	92.8	20.9	3,782	0	25.2%	46.7%
Mar 22, 2004	1,364.7	16,733	93.8	21.1	4,437	0	25.9%	52.0%
Mar 23, 2004	1,365.1	16,834	94.5	21.2	4,724	0	25.8%	53.4%
Mar 24, 2004	1,365.9	17,335	93.9	21.0	3,965	0	25.0%	47.5%
Mar 25, 2004	1,365.9	17,335	93.9	20.9	3,898	0	25.0%	47.1%
Mar 26, 2004	920.0	11,723	63.3	14.1	2,023	0	24.9%	41.8%
Mar 27, 2004	0.0	0	0.0	0.0	0	0		
Mar 28, 2004	0.0	0	0.0	0.0	0	0		
Mar 29, 2004	0.0	0	0.0	0.0	0	0		
Mar 30, 2004	29.3	401	4.0	0.7	113	0	21.5%	49.2%
Mar 31, 2004	136.6	2,204	26.7	5.8	53	0	17.0%	18.5%
Totals	***35,160***	***440,680***	***2,426***	***544***	***102,987***	***0***	***25.4%***	***48.3%***

Note: Actual natural gas HHV is used.

Table B-13. Microturbine Generation and CHP Performance – April 2004

	[1]	[2]	[3]	[4]	[5]	[6]	[7] = [1-3] / [2]	[8] = [1-3-4+5+6] / [2]
	Turbine		Parasitic Loads		Heat Recovered			
Date	Power Output (kWh)	Gas Input (MBTU)	Gas Compressor (kWh)	Heat Recovery Glycol Pump (kWh)	Space Heating (MBTU)	Desiccant Regen (MBTU)	"Net" Turbine Generation Efficiency (%)	"Net" CHP Efficiency (%)
Apr 1, 2004	253.5	4,108	57.3	12.9	41	0	16.3%	16.2%
Apr 2, 2004	0.0	0	0.0	0.0	0	0		
Apr 3, 2004	0.0	0	0.0	0.0	0	0		
Apr 4, 2004	0.0	0	0.0	0.0	0	0		
Apr 5, 2004	0.0	0	0.0	0.0	0	0		
Apr 6, 2004	0.0	0	0.0	0.0	0	0		
Apr 7, 2004	0.0	0	0.0	0.0	0	0		
Apr 8, 2004	0.0	0	0.0	0.0	0	0		
Apr 9, 2004	246.0	4,108	52.0	11.6	624	0	16.1%	30.3%
Apr 10, 2004	462.0	7,615	93.3	20.9	1,873	0	16.5%	40.2%
Apr 11, 2004	431.9	7,214	93.5	20.8	2,067	0	16.0%	43.7%
Apr 12, 2004	241.8	4,008	53.1	11.8	1,080	0	16.1%	42.0%
Apr 13, 2004	0.0	0	0.0	0.0	0	0		
Apr 14, 2004	170.9	2,906	37.5	8.4	755	0	15.7%	40.7%
Apr 15, 2004	449.2	7,315	93.3	20.9	1,989	0	16.6%	42.8%
Apr 16, 2004	445.3	7,415	93.7	20.9	1,943	0	16.2%	41.4%
Apr 17, 2004	433.3	7,315	93.6	20.9	1,782	0	15.9%	39.2%
Apr 18, 2004	170.5	3,006	42.1	9.3	580	0	14.6%	32.8%
Apr 19, 2004	0.0	0	0.0	0.0	0	0		
Apr 20, 2004	0.0	0	0.0	0.0	0	0		
Apr 21, 2004	0.0	0	0.0	0.0	0	0		
Apr 22, 2004	0.0	0	0.3	0.0	0	0		
Apr 23, 2004	0.0	0	0.0	0.0	0	0		
Apr 24, 2004	0.0	0	0.0	0.0	0	0		
Apr 25, 2004	0.0	0	0.0	0.0	0	0		
Apr 26, 2004	0.0	0	0.0	0.0	0	0		
Apr 27, 2004	0.0	0	0.0	0.0	0	0		
Apr 28, 2004	0.0	0	0.0	0.0	0	0		
Apr 29, 2004	0.0	0	0.0	0.0	0	0		
Apr 30, 2004	165.9	2,305	12.6	2.7	144	0	22.7%	28.5%
Totals	***3,470***	***57,315***	***722***	***161***	***12,878***	***0***	***16.4%***	***37.9%***

Note: Actual natural gas HHV is used.

APPENDIX C

CAPSTONE LOGS AND INCIDENT HISTORY

The table below presents a log of incidents (i.e., fault logs) during the monitoring period for the Capstone Controller. The logs are incomplete in some periods when logs could not be downloaded from the controller. Manual restarts did not create a log entry, but they were added into the table for reference.

Table Legend	
(orange)	Turbine Down/Unsuccessful Restart
(yellow)	Turbine Successful Auto-restart
(green)	Turbine Successful Manual Restart (No Logs)

Table C-1. Capstone Controller Incident History (logs downloaded from controller)

Capstone Log					
Number	Description	Type	Date	Time	Additional Information
6007	ENG OVER SPEED	Internal Fault	3/26/2004	14:50:52	
6015	GEN PWR FOLDBK	Intrnl Warning	3/26/2004	14:50:35	
6007	ENG OVER SPEED	Internal Fault	3/26/2004	14:48:35	
6015	GEN PWR FOLDBK	Intrnl Warning	3/26/2004	14:48:19	
6007	ENG OVER SPEED	Internal Fault	3/26/2004	14:46:18	
6015	GEN PWR FOLDBK	Intrnl Warning	3/26/2004	14:46:03	
6007	ENG OVER SPEED	Internal Fault	3/26/2004	14:44:03	
6007	ENG OVER SPEED	Internal Fault	3/26/2004	14:41:03	
10048	IDSP FST OV B	PRT RLY Fault	3/17/2004	10:00:29	
6012	FLAMEOUT LOAD	Fuel Fault	3/9/2004	14:40:11	
6012	FLAMEOUT LOAD	Fuel Fault	3/9/2004	14:38:15	
10044	IDSP ACT ISL	ANT-ISL Fault	2/19/2004	7:39:31	
10014	IDSP OC A	Grid Fault	2/19/2004	7:39:31	
10016	IDSP OC C	Grid Fault	2/19/2004	7:39:31	
10019	IDSP DLTA FREQ	PRT RLY Fault	2/19/2004	7:39:31	
10047	IDSP FST OV A	PRT RLY Fault	2/18/2004	6:52:53	
	NO LOG		2/9/2004	14:30:00	Turbine Restarted
7000	MANUAL E-STOP	E Stop Fault	2/9/2004	13:30:05	
6007	ENG OVER SPEED	Internal Fault	2/9/2004	13:24:06	
6007	ENG OVER SPEED	Internal Fault	2/9/2004	13:21:52	
10044	IDSP ACT ISL	ANT-ISL Fault	2/9/2004	12:15:06	
10019	IDSP DLTA FREQ	PRT RLY Fault	2/9/2004	12:15:06	
9008	GDSP OC A	Internal Fault	1/28/2004	3:13:28	Turbine Down
	NO LOG		1/22/2004	10:00:00	Turbine Restarted
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:28:16	Turbine Down
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:24:00	Single Phase Overvoltage Faults
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:19:45	Voltage observed from 291-293 day of restart
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:15:24	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:10:53	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	14:06:07	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	13:53:38	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	13:38:36	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:57:47	

Capstone Log					
Number	**Description**	**Type**	**Date**	**Time**	**Additional Information**
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:52:06	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:47:25	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:42:40	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:37:59	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:32:01	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:25:48	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:21:27	x
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:17:03	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:12:20	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:04:55	
10008	IDSP OV A	PRT RLY Fault	1/20/2004	12:00:01	
	NO LOG		12/4/2003	12:00:00	Turbine Restarted
6006	FAIL TO LIGHT	Fuel Fault	11/14/2003	8:55:42	Engine Replaced
6006	FAIL TO LIGHT	Fuel Fault	11/14/2003	8:53:17	
10051	IDSP FST UV B	PRT RLY Fault	11/13/2003	20:08:34	Turbine Down
	NO LOG		11/10/2003	17:00:00	Turbine Restarted
6006	FAIL TO LIGHT	Fuel Fault	11/10/2003	11:15:26	
6006	FAIL TO LIGHT	Fuel Fault	11/10/2003	11:11:10	
7008	IN FLT2 LVL 3	UsrCon Fault	11/5/2003	19:34:16	Turbine Down
	NO LOG		10/20/2003	10:00:00	Turbine Restarted
10044	IDSP ACT ISL	ANT-ISL Fault	10/18/2003	0:09:21	
10014	IDSP OC A	Grid Fault	10/18/2003	0:09:21	
10015	IDSP OC B	Grid Fault	10/18/2003	0:09:21	
10016	IDSP OC C	Grid Fault	10/18/2003	0:09:21	
10019	IDSP DLTA FREQ	PRT RLY Fault	10/18/2003	0:09:21	Turbine Down
	NO LOG		10/10/2003	19:30:00	Turbine Restarted
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:35:21	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:31:02	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:27:10	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:17:50	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:15:41	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	18:13:35	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	17:17:08	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	16:54:22	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	16:50:51	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	16:25:19	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	16:17:20	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	15:31:29	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	13:50:31	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	13:46:00	
6006	FAIL TO LIGHT	Fuel Fault	10/10/2003	13:36:34	
	NO LOG		10/9/2003	12:00:00	Turbine Down
	NO LOG		10/2/2003	15:30:00	Turbine Restarted
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	15:07:19	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	15:05:27	

Capstone Log					
Number	Description	Type	Date	Time	Additional Information
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	15:03:35	
6010	HI OVER TEMP	Fuel Fault	10/2/2003	15:01:43	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	15:00:00	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:58:08	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:53:34	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:51:42	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:48:59	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:42:47	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	14:40:55	
6006	FAIL TO LIGHT	Fuel Fault	10/2/2003	13:35:14	
6006	FAIL TO LIGHT	Fuel Fault	9/29/2003	14:01:51	
6006	FAIL TO LIGHT	Fuel Fault	9/29/2003	13:59:59	
6006	FAIL TO LIGHT	Fuel Fault	9/29/2003	13:58:07	
6006	FAIL TO LIGHT	Fuel Fault	9/29/2003	13:56:15	
6005	FAIL TO ROTATE	Internal Fault	9/29/2003	13:54:34	
6001	DC BUS UV	Internal Fault	9/29/2003	13:52:03	Turbine Down
10044	IDSP ACT ISL	ANT-ISL Fault	9/25/2003	12:07:11	
10014	IDSP OC A	Grid Fault	9/25/2003	12:07:11	
10016	IDSP OC C	Grid Fault	9/25/2003	12:07:11	
10019	IDSP DLTA FREQ	PRT RLY Fault	9/25/2003	12:07:11	
	NO LOG		9/13/2003	8:00:00	Turbine Restarted
10044	IDSP ACT ISL	ANT-ISL Fault	9/12/2003	20:37:42	
10015	IDSP OC B	Grid Fault	9/12/2003	20:37:42	
10016	IDSP OC C	Grid Fault	9/12/2003	20:37:42	
10019	IDSP DLTA FREQ	PRT RLY Fault	9/12/2003	20:37:42	Turbine Down
	NO LOG		9/11/2003	15:00:00	Turbine Restarted
10048	IDSP FST OV B	PRT RLY Fault	9/11/2003	13:35:57	
10044	IDSP ACT ISL	ANT-ISL Fault	9/11/2003	12:45:56	
10019	IDSP DLTA FREQ	PRT RLY Fault	9/11/2003	12:45:56	
6006	FAIL TO LIGHT	Fuel Fault	9/11/2003	12:45:22	
6006	FAIL TO LIGHT	Fuel Fault	9/11/2003	12:16:21	
6006	FAIL TO LIGHT	Fuel Fault	9/11/2003	12:06:07	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	12:18:43	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	12:16:51	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	12:14:25	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	11:57:36	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	11:55:44	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	11:42:27	
6006	FAIL TO LIGHT	Fuel Fault	9/10/2003	11:21:34	
6006	FAIL TO LIGHT	Fuel Fault	9/8/2003	15:10:10	
10044	IDSP ACT ISL	ANT-ISL Fault	9/8/2003	15:03:23	
10019	IDSP DLTA FREQ	PRT RLY Fault	9/8/2003	15:03:23	
6006	FAIL TO LIGHT	Fuel Fault	8/15/2003	11:47:52	
6006	FAIL TO LIGHT	Fuel Fault	8/15/2003	11:46:00	
6027	LOW DCBUS VOLT	Grid Fault	8/15/2003	11:42:49	

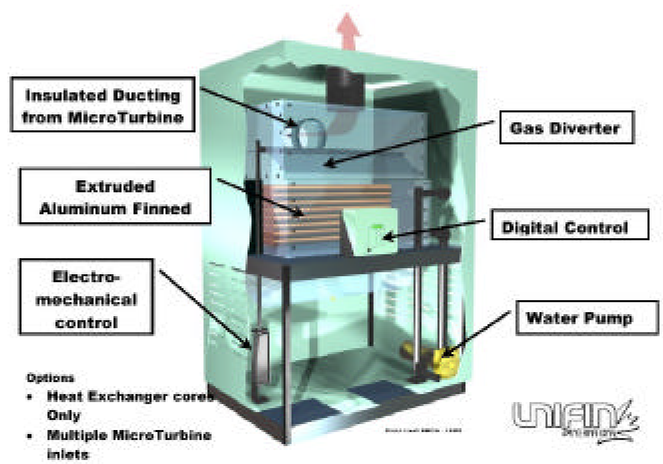
Capstone Log					
Number	Description	Type	Date	Time	Additional Information
6006	FAIL TO LIGHT	Fuel Fault	8/15/2003	11:41:54	
6006	FAIL TO LIGHT	Fuel Fault	8/12/2003	16:59:29	
6006	FAIL TO LIGHT	Fuel Fault	8/11/2003	10:24:36	
6006	FAIL TO LIGHT	Fuel Fault	8/11/2003	10:22:44	
6006	FAIL TO LIGHT	Fuel Fault	8/11/2003	10:20:52	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	1:07:16	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	1:04:09	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	1:01:18	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	0:58:23	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	0:55:16	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	0:51:48	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	0:47:58	
7008	IN FLT2 LVL 3	UsrCon Fault	8/10/2003	0:44:03	Turbine Down
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:52:11	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:36:33	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:26:02	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:15:58	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:05:18	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	22:00:47	
7008	IN FLT2 LVL 3	UsrCon Fault	8/7/2003	19:31:43	
10047	IDSP FST OV A	PRT RLY Fault	7/29/2003	15:48:37	
10044	IDSP ACT ISL	ANT-ISL Fault	7/11/2003	13:22:23	
10019	IDSP DLTA FREQ	PRT RLY Fault	7/11/2003	13:22:23	
6012	FLAMEOUT LOAD	Fuel Fault	7/2/2003	12:36:39	
11000	GDSP SPI COMM	Internal Fault	7/2/2003	12:29:50	
4011	SW COMPATIBILTY	Internal Fault	7/2/2003	12:29:50	
10056	IDSP PWR RESET	Intrnl Warning	7/2/2003	12:29:48	
11001	IDSP SPI COMM	Internal Fault	7/2/2003	12:29:47	
10060	DCOMP DISABLED	Intrnl Warning	7/2/2003	12:29:47	
11001	IDSP SPI COMM	Internal Fault	6/30/2003	12:57:32	
10044	IDSP ACT ISL	Grid Fault	6/30/2003	12:55:01	
10019	IDSP DLTA FREQ	Grid Fault	6/30/2003	12:55:01	
7005	IN FLT1 LVL 3	UsrCon Fault	6/27/2003	10:58:46	
11001	IDSP SPI COMM	Internal Fault	6/22/2003	7:20:43	
10044	IDSP ACT ISL	Grid Fault	6/22/2003	7:18:12	
10014	IDSP OC A	Grid Fault	6/22/2003	7:18:12	
10015	IDSP OC B	Grid Fault	6/22/2003	7:18:12	
10016	IDSP OC C	Grid Fault	6/22/2003	7:18:12	
10019	IDSP DLTA FREQ	Grid Fault	6/22/2003	7:18:12	
	NO LOG		5/23/2003	10:00:00	Turbine Restarted
9007	GDSP DCBUS OV	Internal Fault	5/21/2003	11:40:04	
10044	IDSP ACT ISL	Grid Fault	5/15/2003	15:39:18	Turbine Down

APPENDIX D

CHP SYSTEM SCHEMATICS, PHOTOS, AND INSTALLATION DETAILS

The CHP system included three major components: 1) the Capstone 60 microturbine (Serial No. 001689), 2) the Unifin heat exchanger (second generation version) and 3) the Copland scroll gas compressor. These components are shown in Figure D-1.

Capstone 60 Microturbine



Gas Compressor

Figure D-1. Main BCHP Components

CHP Skid and Munters AHU
(before Screens were installed around AHU)

Finished Skid - Front

Finished Skid – Rear

<< Capstone with Snow Shroud Installed Dec-03

Ground Level Disconnect at Rear of Store

Microturbine with Disconnects at Roof

Figure D-2. Various Photos of System Installation

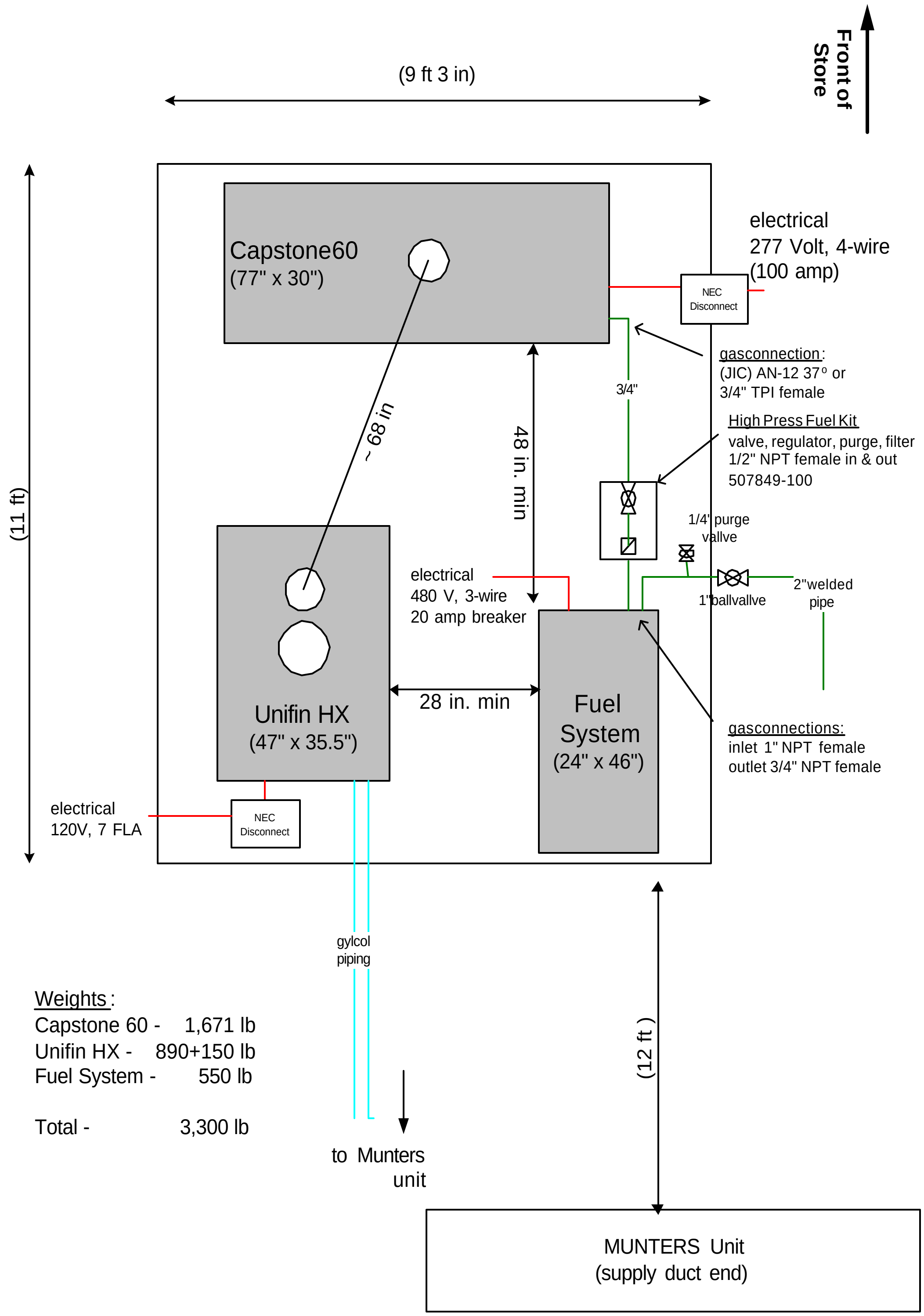


Figure D-3. Layout of Microturbine Skid on Rooftop Near Munters AHU

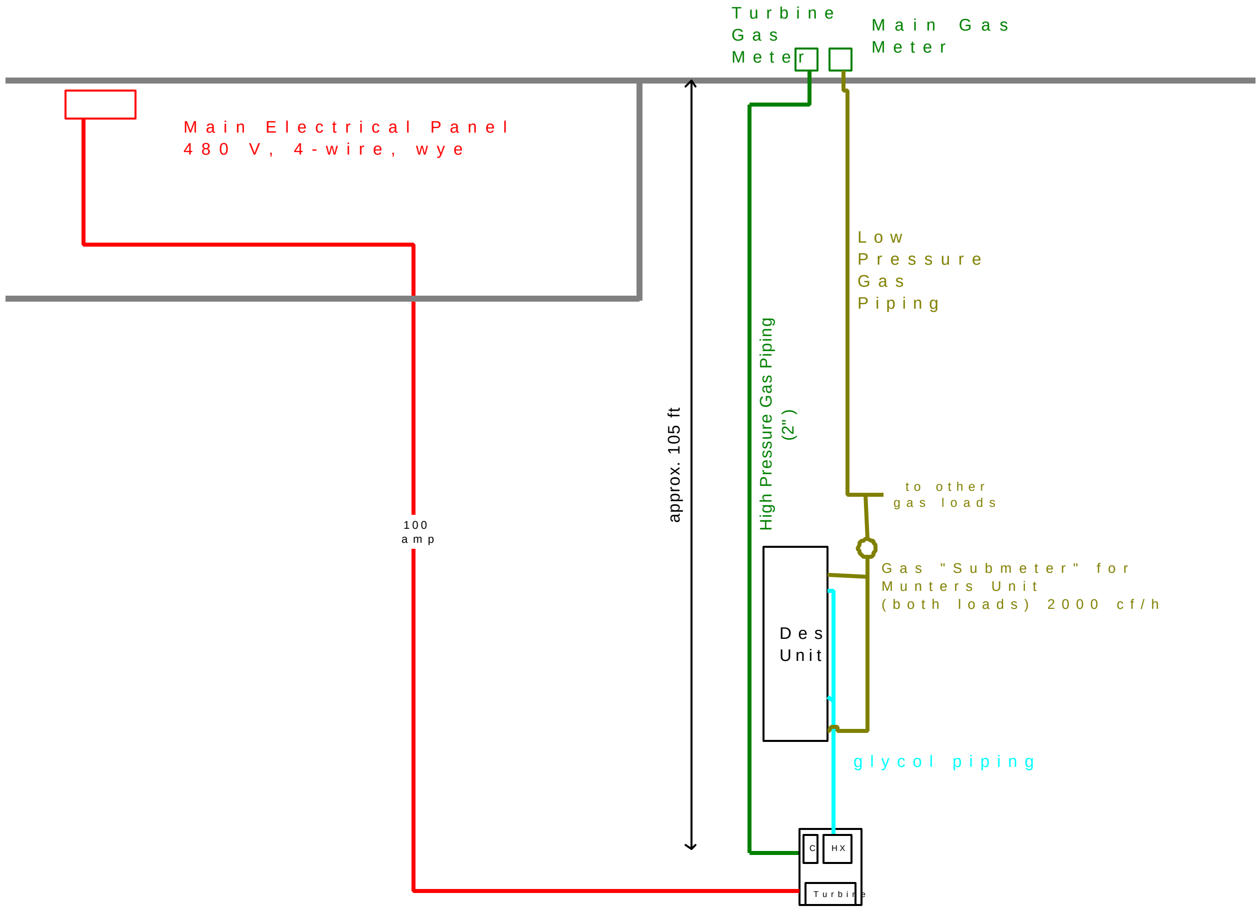


Figure 4. Layout of Microturbine Skid and Munters AHU on Roof

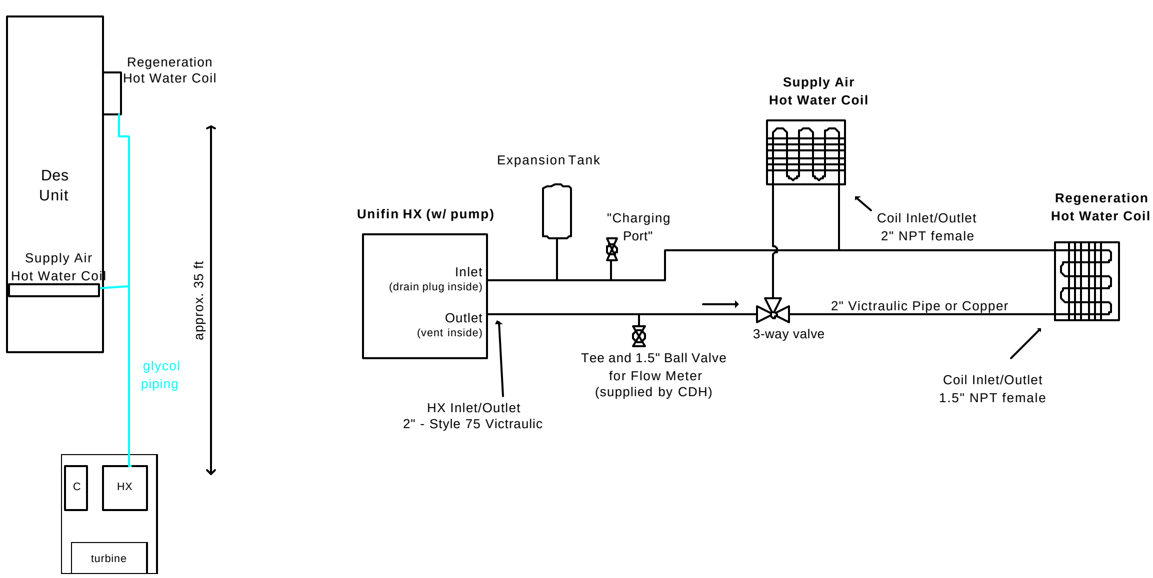


Figure 5. Glycol Piping Details Between Unifin HX and Munters AHU

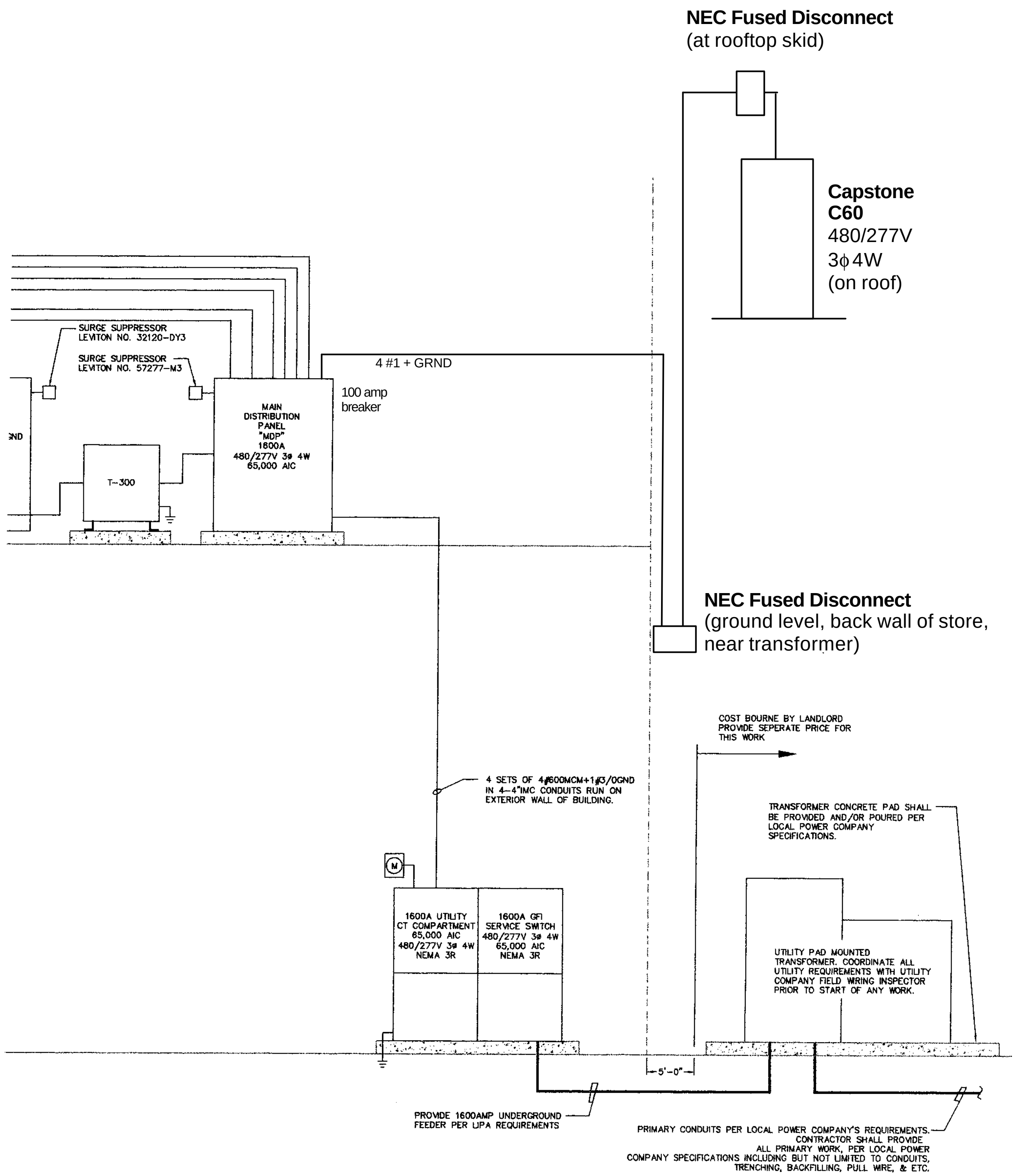


Figure D-6. Electrical System at Waldbaums Supermarket

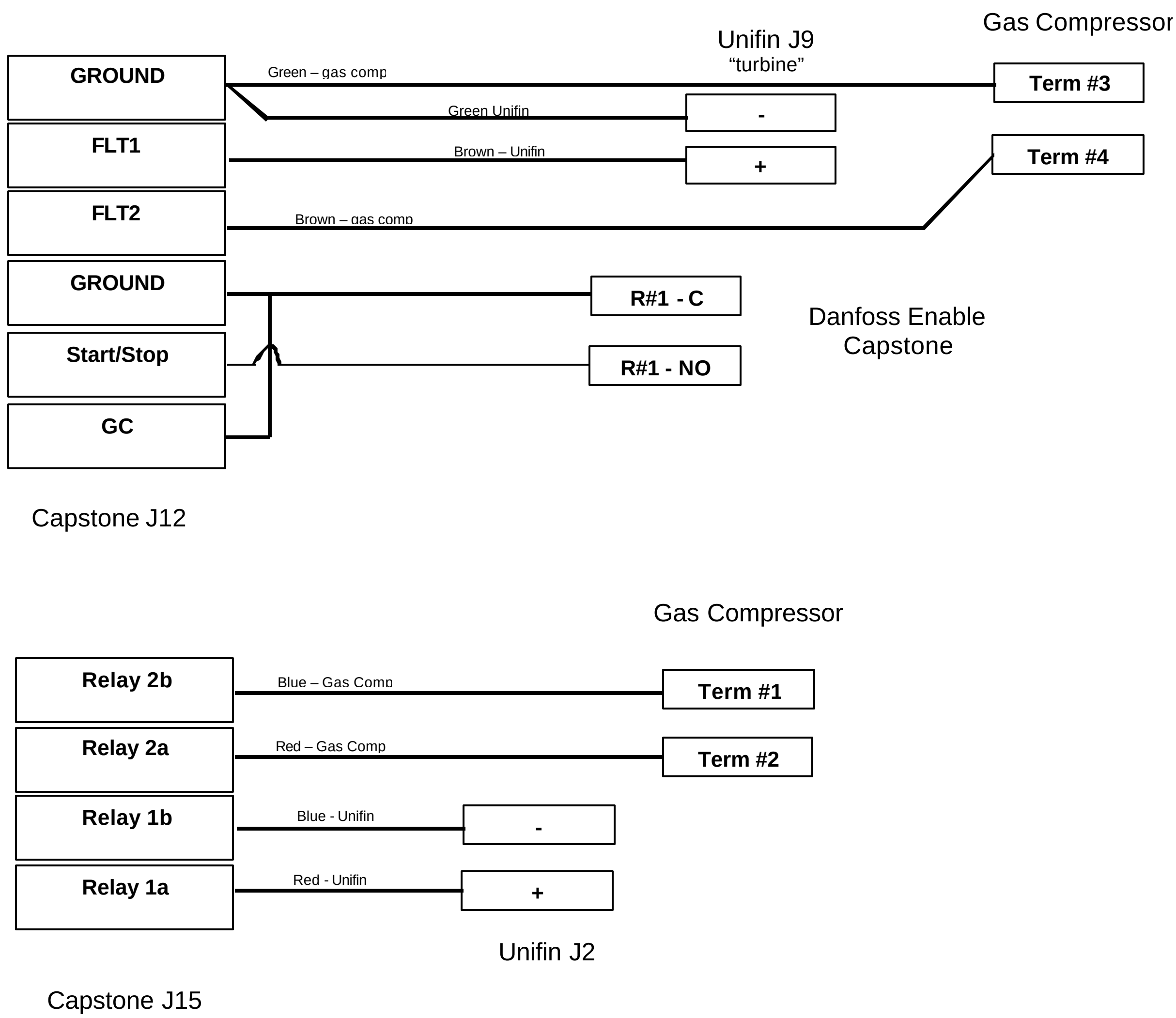


Figure D-7. Control Wiring for Capstone, Unifin, and Gas Compressor

Danfoss Control Logic for Capstone/Unifin/Munters System

June 4, 2002

New Danfoss Outputs

1.	Capstone Enable Relay (terminals 5-3 on J12 in Com Bay)	NO contact/Skid
2.	Enable Heat Recovery System (J8 on Unifin)	NC contact/Skid
3.	Glycol Diverter Valve (field-installed 120V solenoid valve)	NC contact/Munters Unit

New Danfoss Inputs (all on control board for skid)

1.	Capstone "Run" Signal (Relay 2, J15 in Com Bay)	NO contact/Skid
2.	Capstone "Fault" Signal (Relay 4, J15 in Com Bay)	NO contact/Skid
3.	Unifin Alarm Output J1 (exhaust gas too hot)	NO contact/Skid
4.	Unifin Alarm Output J3 (water too hot)	NO contact/Skid
5.	Unifin Alarm Output J5 (failed diverter valve)	NO contact/Skid
6.	Unifin Alarm Output J7 (no flow)	NO contact/Skid

Control Logic

Microturbine

Capstone will be manually enabled/disabled from the Danfoss System (output 1 above) to allow remote control by A&P.

Dehumidification

If the DH signal on the Munters unit is enabled, then also enable the Heat Recovery System (output 2). This will preheat the air entering the regeneration burner.

Space Heating

The first stage of heating on the Munters unit should be the heat recovery coil (make the gas furnace sections stages 2 & 3). When stage 1 is required enable the Heat Recovery Valve and the Glycol Diverter Valve (outputs 2 and 3). The heat recovery coil will get the first shot at meeting the space heating load. This 1^{st} stage set point could be slightly warmer than the default stage 1 setting to provide a wider spread between the stages.

Figure D-8 shows the layout of the Munters unit. The red arrows in Figure D-8 show the air path through the Munters unit. Return air from the space and makeup air from outdoors mix at the center plenum of the unit as shown. If dehumidification is required – as indicated by a humidistat located in the space – some mixed air (mostly outdoor air) is pulled through the desiccant unit by the process fan. This dry process air is then returned over top of the desiccant module back into the top of the center plenum. The supply fan pulls air from the center plenum through DX cooling coil and then through the heating section of the unit. When dehumidification is not required, all the mixed air bypasses the desiccant wheel and is pulled through the cooling coil directly.

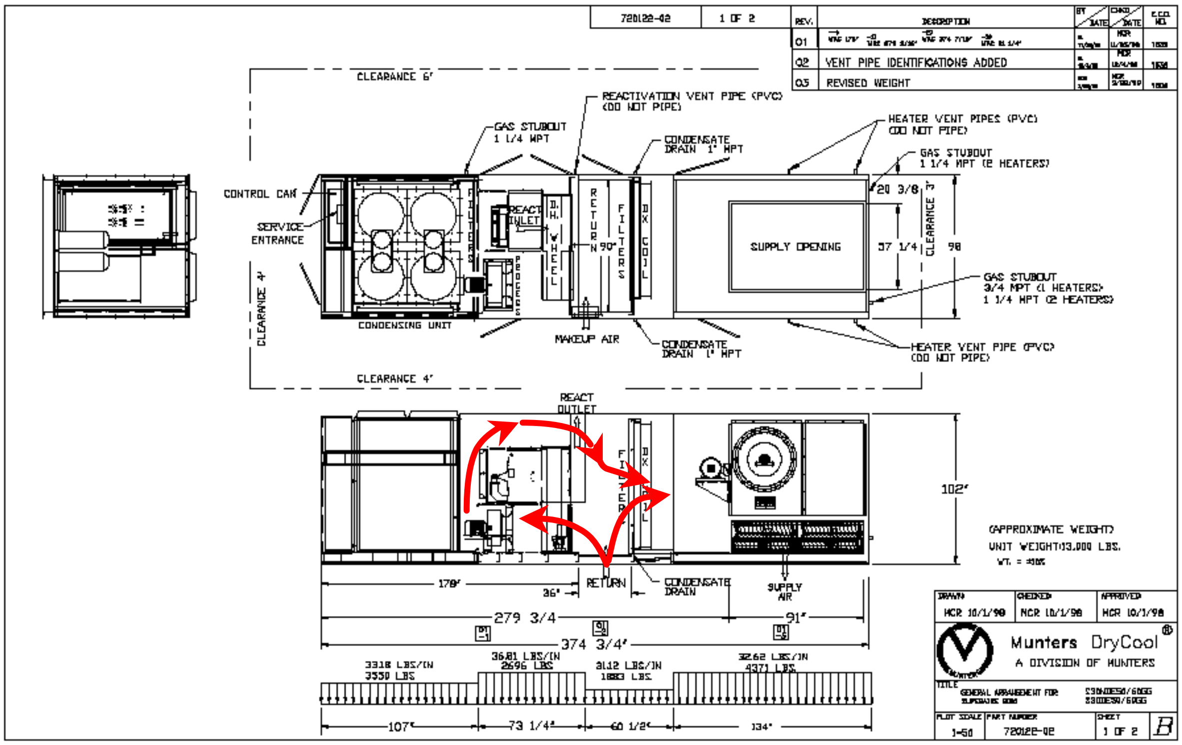


Figure D-8. Layout of Munters Unit

Space Heating Coil Installed in the Munters Unit

NOV-05-2001 MON 01:15 PM MUNTERS DRYCOOL FAX NO. 19789211969 P. 02

Heatcraft Commercial Products **FLUID SELECTION** 4.20.04.1070

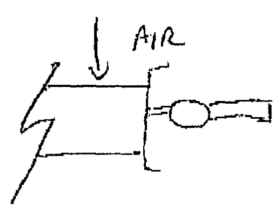
Date:	10/10/01		
Customer:		From:	Mike Nelson
Contact:	HW 004519	Company:	Munters Dry Cool
Job:		Return Tel:	210-249-3847
Fax:		Return Fax:	210-651-9085

GIVEN DATA

Construction		Air Side	
Item:	Post heat	Air Flow (SCFM)	20,000.00
Coils Per Bank:	1	Altitude (FT):	0.00
Allow Opp. End:	No	Ent. Air DB (°F):	51.00
Tube OD (IN):	5/8	Lvg. Air DB (°F):	0.00
Coil Duty:	Heat-Return Bend	Total Capacity (MBH):	380.00
Fins Per Inch:	7	Max Air PD (IN WG):	0.00
Rows:	1	**Fluid Side**	
Fin Surface:	C	Fluid Type:	Ethylene
Fin Height (IN):	78.00	Percent Glycol:	50
Finned Length (IN):	83.00	Ent. Fluid (°F):	140.00
Tubing Mat. (IN)	0.020 Copper	Lvg. Fluid (°F):	0.00
Fin Mat. (IN)	0.0075 Aluminum	Fluid Flow (GPM):	35.00
Conn Qty/Size (IN):	1 / Optimize	Max FPD (FT H20):	10.00
Circuiting:	Optimize	TurboSpirals:	No

OUTPUT DATA		Most Economical			Specified Coil		
		1	2	3	4	5	6
Model Number:					5MQ0701C		
Velocity:	(SFPM)				444.86		
Total Capacity:	(MBH)				372.14		
Sens. Capacity:	(MBH)				0.00		
Lvg. Air DB:	(°F)				68.16		
Lvg. Air WB:	(°F)				0.00		
Standard APD	(IN WG)				0.10		
Lvg. Fluid:	(°F)				115.58		
Fluid Flow:	(GPM)				35.00		
Fluid PD:	(FT H20)				3.55		
Fluid Vel.:	(FPS)				2.93		
Conn Size:	(IN)				2.00		
Weight:	(LB)				196		
Notes:					BCGKL		

Notes:
B) Rated In Compliance With ARI 410.
C) Coil Not Within Certified ARI Directory.
G) Load below specification. Consult factory.
K) Face and Row spacing on 1.5 inch centers
L) Coil rating valid for Heatcraft coils only.



INVERT TOP FLANGE

Page 1

NOV-05-2001 MON 01:16 PM MUNTERS DRYCOOL FAX NO. 19789211969 P. 03

Heatcraft Commercial Products **FLUID SELECTION** 4.20.04.1070

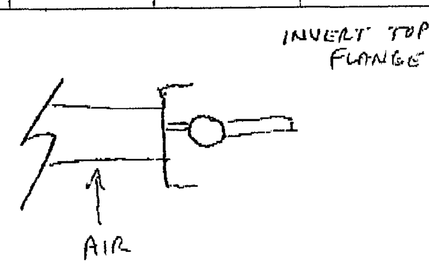
Date:	10/10/01	From:	Mike Nelson
Customer:		Company:	Munters Dry Cool
Contact:	HW 804519A	Return Tel:	210-249-3847
Job:		Return Fax:	210-651-9085
Fax:			

GIVEN DATA

Construction		**Air Side**	
Item:	React	Air Flow (SCFM)	2,850.00
Coils Per Bank:	1	Altitude (FT):	0.00
Allow Opp. End:	No	Ent. Air DB (°F):	45.00
Tube OD (IN):	5/8	Lvg. Air DB (°F):	0.00
Coil Duty:	Heat-Return Bend	Total Capacity (MBH):	300.00
Fins Per Inch:	8	Max Air PD (IN WG):	0.00
Rows:	4	**Fluid Side**	
Fin Surface:	A	Fluid Type:	Ethylene
Fin Height (IN):	36.00	Percent Glycol:	50
Finned Length (IN):	25.00	Ent. Fluid (°F):	200.00
Tubing Mat. (IN)	0.020 Copper	Lvg. Fluid (°F):	0.00
Fin Mat. (IN)	0.0075 Aluminum	Fluid Flow (GPM):	35.00
Conn Qty/Size (IN):	1 / Optimize	Max FPD (FT H20):	10.00
Circuiting:	Optimize	TurboSpirals:	No

OUTPUT DATA		Most Economical			Specified Coil		
		1	2	3	4	5	6
Model Number:					5WH0804A		
Velocity:	(SFPM)				456.00		
Total Capacity:	(MBH)				296.88		
Sens. Capacity:	(MBH)				0.00		
Lvg. Air DB:	(°F)				141.05		
Lvg. Air WB:	(°F)				0.00		
Standard APD	(IN WG)				0.19		
Lvg. Fluid:	(°F)				180.80		
Fluid Flow:	(GPM)				35.00		
Fluid PD:	(FT H20)				5.22		
Fluid Vel.:	(FPS)				3.17		
Conn Size:	(IN)				1.50		
Weight:	(LB)				104		
Notes:					BCGIL		

Notes:
B) Rated In Compliance With ARI 410.
C) Coil Not Within Certified ARI Directory.
G) Load below specification. Consult factory.
I) Header Pressure Drop Exceeds 30% of Total Fluid Pressure Drop.
L) Coil rating valid for Heatcraft coils only.



Nominal Specifications of the Munters AHU from Store Design Drawings

SUPERMARKET TYPE HVAC EQUIPMENT SCHEDULE

DESIGN CONDITIONS: SUMMER : OUTSIDE = 94 DEG.F. DB/106 GRLLB, INSIDE = 75 DEG.F. DB/46 GRLLB; WINTER : OUTSIDE = 0 DEG.F. DB, INSIDE = 70 DEG.F. DB

RTU-1

MANUFACTURER/MODEL NO.		
MUNTERS DRYCOOL	S30ND45GG	
TELEPHONE: 1-800-229-8557		
LOCAL: 1-704-366-0908		
SERVICE AREA	SALES AREA	
UNIT WEIGHT	13,000	
SUPPLY AIR BLOWER		
TOTAL CFM	20,000	
OUTSIDE AIR CFM	5,500	
RETURN CFM	14,500	
SIZE	36 DWDI	
TYPE/CLASS	BAF/I	
TOTAL STATIC PRESSURE	3.72 W.G.	
EX. STATIC PRESSURE	1.5" W.G.	
FAN RPM	890	
FAN BHP	15.7	
MOTOR HP	20	
PROCESS FAN		
SIZE	16"x80% SWSI	
TYPE/CLASS	BAF/I	
AIR VOLUME	9,000	
FAN RPM	917	
FAN BHP	8.2	
MOTOR HP	10	
TOTAL STATIC PRESSURE	2.52" W.G.	
REACTIVATION FAN		
SIZE	16"x80% SWSI	
TYPE/CLASS	BAF/III	
FAN RPM	3450	
AIR VOLUME	3250	
TOTAL STATIC PRESSURE	5.53" W.G.	
MOTOR HP	7.5	
REACTIVATION HEATER		
TYPE OF GAS	NATURAL	
CAPACITY INPUT	750,000 MAX BTUH	
STAGES OF CAPACITY	MODULATING	
GAS SUPPLY PRESSURE REQ'D	6"-15" WG	
GAS PRESSURE AT PILOT	3.5" WG	
MANIFOLD PRESSURE	4.5" WG	
PRESSURE DROP ACROSS BURNER	0.7" WG	
DESICCANT WHEEL		
MOISTURE REMOVAL (LB/HR)	263	
PRESSURE DROP PROCESS	1.9" W.G.	
PRESSURE DROP REACTIVATION	2.47" W.G.	
FILTERS		
TYPE	30% PLEATED	
NUMBER/SIZE	(24) 16 x 20 x 2 (10) 16 x 25 x 2	
COOLING COIL		
SENSIBLE CAPACITY (BTUH)	680,400	
COIL CIRCUITS	2	
ROWS/FPI	3/11	
FACE AREA (SQ. FT.)	50.15	
ENTERING AIR (DB / GR/LB)	97.5/42	
LEAVING AIR (DB / GR/LB)	66/42	
CONDITIONED AIR (SCFM)	20,000	
COIL P (WG)	0.42" WG	
CONDENSER	**A**	**B**
COMPRESSORS/HP	30	30
STAGES	2	2
COIL FACE AREA (SQ.FT.)	42.5	42.5
ROWS/FPI	4/10	4/10
CONDENSER FAN HP	1.5	1.5
CONDENSER FAN RPM	1140	1140
AUXILIARY HEAT		
INPUT (BTUH)	1,600,000	
OUTPUT (BTUH)	1,208,000	
TYPE	NATURAL GAS	
STAGES OF CAPACITY	2	
ELECTRICAL DATA:		
SYSTEM VOLTAGE (V/P/H)	460/3/60	
CONTROL CIRCUIT VOLTAGE	110 V	
SUPPLY MOTOR	23.2 AMPS	
PROCESS MOTOR	12.2 AMPS	
REACTIVATION MOTOR	8.8 AMPS	
DESICCANT WHEEL MOTOR	0.9 AMPS	
COMPRESSOR A	55.2 AMPS	
COMPRESSOR B	55.2 AMPS	
CONDENSING FANS	12 AMPS	
CONTROL TRANSFORMER	4.3 AMPS	
UNIT FLA	171.8 AMPS	
UNIT MCA	178.7 AMPS	
UNIT MOP	200 AMPS	
DISCONNECT SIZE	200 AMPS	

ACCESSORIES:

(1) UNIT HOUSING CONSTRUCTED OF EMBOSSED ALUMINUM PANELS WITH A MINIMUM OF 1 INCH FIBERGLASS DUCT BOARD INSULATION MECHANICALLY SECURED ON ALL SIDES.
(2) TITANIUM SILICA GEL DESICCANT WHEEL AND CONTROLS
(3) PHASE LOSS/LOW VOLTAGE PROTECTION RELAY.
(4) FARR 3030 FILTERS
(5) PROVIDE BURGLAR BARS AT ROOF LEVEL.
(6) SINGLE RETURN
(7) 12" HIGH, SLOPED UNIT CURB.
(8) PREMIUM EFFICIENCY BLOWER MOTORS.
(9) WALK IN SERVICE VESTIBULE
(10) NON-FUSED DISCONNECT; CONVENIENCE OUTLET
(11) SUPPLY AND RETURN AIR SMOKE DETECTOR PROVIDED & FACTORY INSTALLED BY UNIT MANUFACTURER.
(12) CARLYLE COMPRESSORS WITH SUCTION UNLOADING, LIQUID LINE SOLENOID VALVE, SIGHT GLASS AND REPLACEABLE CORE FILTER/DRIER.
(13) EACH CIRCUIT SHALL INCLUDE HIGH PRESSURE CUT-OUT, OIL FAILURE SWITCH, LOW PRESSURE CUT-OUT, OFF/RUN/PUMP DOWN SWITCH AND FAN CYCLING TO 50F.
(14) UNIT TO BE INSTALLED LEVEL.
(15) STAINLESS STEEL DRAIN PANS.
(16) BIRDSCREEN ON ALL OUTDOOR AIR INLETS.
(17) ALL WIRES TO BE NUMBERED & COLOR-CODED.
(18) FACTORY ASSISTED STARTUP.

NOTE: PROVIDE ALL ACCESSORIES AND OPTIONS AS PER A&P STANDARD SPECIFICATIONS

APPENDIX E

EMISSIONS READINGS FOR MICROTURBINE AND OTHER EQUIPMENT

AND

DETERMINING THE ENERGY CONTENT OF NATURAL GAS

Table E-1. Summary of Emissions Readings Collected by CDH Energy

Turbine

	Hole in Stack			Hole in Stack			Top of Stack		
	9/17/2003	**9/17/2003**	**9/17/2003**	6/9/2004	6/9/2004	**6/9/2004**	6/9/2004	6/9/2004	6/9/2004
	13:41:23	**13:46:11**	**13:49:13**	12:07:31	12:08:24	**12:09:49**	11:17:56	11:19:47	11:20:50
O_2 (ppmv)	**17.26**	**17.08**	**17.35**	17.85	17.81	**17.8**	17.84	17.97	17.82
CO (ppmv)	**1.8**	**2.1**	**1.9**	2	12	**10**	10	6	18
SO_2 (ppmv)	**0**	**0**	**0**	0	2	**2**	22	4	15
NO (ppmv)	**2.9**	**3.1**	**3.2**	4	3	**3**	6	3	3
NO_2 (ppmv)	**0**	**0**	**0**	0	0	**0**	0	0	0
NOx (ppmv)	**2.3**	**3.1**	**3.2**	4	3	**3**	6	3	3
Tambient (F)	**83.7**	**76.5**	**78.8**	75.8	77.4	**79.8**	82.4	81.2	79.8
Tflue (F)	**606.1**	**605.9**	**606.9**	588.9	596.6	**598.8**	570.8	578.7	584.4
CO_2 (%)	**2.06**	**2.16**	**2.01**	1.73	1.75	**1.76**	1.74	1.66	1.75
Corrected									
CO @ 15% O_2 (ppmv)	**2.9**	**3.2**	**3.2**	3.9	22.9	**19.0**	19.3	12.1	34.5
NO_x @ 15% O_2 (ppmv)	**3.7**	**4.8**	**5.3**	7.7	5.7	**5.7**	11.6	6.0	5.7
SO_2 @ 15% O_2 (ppmv)	**-**	**-**	**-**	-	3.8	**3.8**	42.4	8.1	28.7

Notes: Readings taken with Testo 350XL. Testo unit calibrated for low Nox & low CO scales for September 2003
NOx accuracy: <2 ppm (low NOx), < 5 ppm (std NOx)
CO accuracy: <2 ppm (low CO), < 5 ppm (std CO)
Correction Factor to 15% O_2: 5.9/(20.9 - %O_2) x [ppm]

Desiccant Burner

	9/17/2003	9/17/2003	6/9/2004	6/9/2004
	13:56:54	13:58:50	11:26:25	11:28:25
O_2 (ppmv)	20.82	20.9	21.06	21.05
CO (ppmv)	4	2.2	0	1
SO_2 (ppmv)	0	0	0	0
NO (ppmv)	1.1	1.3	1	0
NO_2 (ppmv)	0	0	0	0
NOx (ppmv)	1.1	1.3	1	0
Tambient (F)	76.7	77.4	77.2	76.1
Tflue (F)	119.8	120	94.8	95.7
CO_2 (%)				

Table E-2. Accuracy and Calibration Sheet for Testo 350XL

Testo 350XL

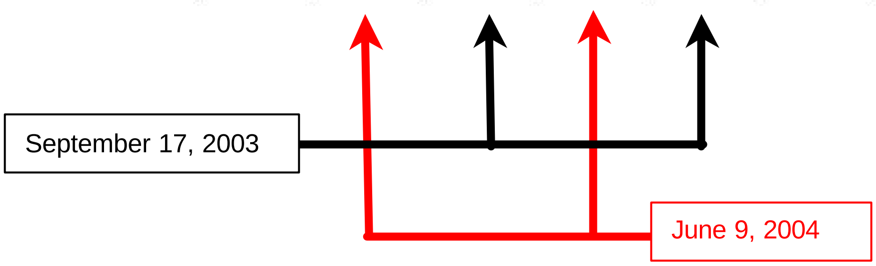
Equipment Specification Sheet: Page 2 of 3

Clean Air Instrument Rental Catalog Number	Testo 350XL Emission Analyzer	**Manufacturer**	Testo
Test Method	CTM-030, CTM-034, ASTM D6522-00	**Equipment Type**	Portable Analyzer

Testo 350XL Parameter Options & Specifications

Our Standard cell configuration is NO (0-3000ppm), NO2, CO (0-10,000ppm), O2, & SO2. Advanced notification is necessary for alternative cell requirements.

	O_2	CO	CO low	NO	NO low	NO_2	SO_2	H_2S	C_xH
Range	0-25% Vol.	0-10,000 ppm H_2 comp.	0-500 ppm H_2 comp.	0-3,000 ppm	0-300 ppm	0-500 ppm	0-5,[illegible] ppm	0-300 ppm	0-[illegible]%
Accuracy	< 0.8% of f.v.	< 5 ppm 0-99 ppm < 5% of m.v. 100-2,000 ppm < 10% of m.v. 2,001-10,000 ppm	< 2 ppm 0-39.9 ppm < 5% of m.v. 40-500 ppm	< 5 ppm 0-99 ppm < 5% of m.v. 100-2,000 ppm < 10% of m.v. 2,001-3,000 ppm	< 2 ppm 0-39.9 ppm < 5% of m.v. 300 ppm	<5 ppm 0-99 ppm < 5% of m.v. 500 ppm	< 5 ppm 0-99 ppm < 5% of m.v. 100-2,000 ppm < 10% of m.v. 2,001-5,000 ppm	< 2 ppm 0-[illegible] ppm < 5[illegible] m.v. 40-[illegible] ppm	< 0.04% Vol. 0-0.4 % Vol. < 10% of m.v. 0.41-4% Vol.
Resolution	0.1 vol. %	1 ppm	0.1 ppm	1 ppm	0.1 ppm	0.1 ppm	1 ppm	0.1 ppm	0.0[illegible] vol. %
Resp. Time	20 s (t95)	40 s (t90)	40 s (t90)	30 s (t90)	30 s (t90)	40 s (t90)	[illegible] s (t90)	35 s (t90)	40 s (t90)



Emissions Test Results - September 17, 2003 (PAGE 1)

Turbine

Waldbaums

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:41:23

Fuel: Natur.gas

17.26	%	Oxygen
1.8	ppm	CO
0	ppm	SO2
2.9	ppm	NO
0.0	ppm	NO2
2.9	ppm	NOx
83.7	°F	Ta
606.1	°F	Tf
2.06	%	CO2
8.5	V	Batt.
0.86	l/m	Pump
43.5	%	Efficiency
394.6	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:46:11

Fuel: Natur.gas

17.08	%	Oxygen
2.1	ppm	CO
0	ppm	SO2
3.1	ppm	NO
0.0	ppm	NO2
3.1	ppm	NOx
76.5	°F	Ta
605.9	°F	Tf
2.16	%	CO2
8.4	V	Batt.
0.85	l/m	Pump
45.1	%	Efficiency
373.4	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Unifin: 611
Logger: 613

Heat transf.°F: --- °F

www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:49:13

Fuel: Natur.gas

17.35	%	Oxygen
1.9	ppm	CO
0	ppm	SO2
3.2	ppm	NO
0.0	ppm	NO2
3.2	ppm	NOx
78.8	°F	Ta
606.9	°F	Tf
2.01	%	CO2
8.4	V	Batt.
0.86	l/m	Pump
41.8	%	Efficiency
405.7	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Microturbine

- Full Output (~56 kW)
- Unifin in Bypass
- Ambient (TSI):
  76.6°F 49.5% rh

Desiccant Burner

Waldbaums

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:56:54

Fuel: Natur.gas

20.82	%	Oxygen
4.0	ppm	CO
0	ppm	SO2
1.1	ppm	NO
0.0	ppm	NO2
1.1	ppm	NOx
76.7	°F	Ta
119.8	°F	Tf
------	%	CO2
8.4	V	Batt.
0.87	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:58:50

Fuel: Natur.gas

20.90	%	Oxygen
2.2	ppm	CO
0	ppm	SO2
1.3	ppm	NO
0.0	ppm	NO2
1.3	ppm	NOx
77.4	°F	Ta
120.0	°F	Tf
------	%	CO2
8.4	V	Batt.
0.86	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Ambient

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 14:09:06

Fuel: Natur.gas

21.10	%	Oxygen
0.0	ppm	CO
0	ppm	SO2
0.8	ppm	NO
0.0	ppm	NO2
0.8	ppm	NOx
80.6	°F	Ta
80.0	°F	Tf
------	%	CO2
8.4	V	Batt.
0.89	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/17/03 13:21:02

Fuel: Natur.gas

21.00	%	Oxygen
0.0	ppm	CO
0	ppm	SO2
0.0	ppm	NO
0.0	ppm	NO2
0.0	ppm	NOx
78.4	°F	Ta
76.8	°F	Tf
------	%	CO2
8.8	V	Batt.
1.02	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:55:28
Fuel: Natur.gas 218 ppm

-0.05	% Oxygen
0	PPM CO
217	PPM SO2
2	PPM NO
0.0	PPM NO2
2	PPM NOx
79.6	°F Ta
74.6	°F Tf
11.70	% CO2
10.0	V Batt.
0.85	l/m Pump
------	% Efficiency
-0.2	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:59:27
Fuel: Natur.gas 3%

3.04	% Oxygen
0	PPM CO
2	PPM SO2
2	PPM NO
0.0	PPM NO2
2	PPM NOx
79.6	°F Ta
74.3	°F Tf
10.00	% CO2
10.0	V Batt.
0.86	l/m Pump
------	% Efficiency
15.0	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:36:10 Ambient
Fuel: Natur.gas

21.08	% Oxygen
0	PPM CO
0	PPM SO2
0	PPM NO
0.0	PPM NO2
0	PPM NOx
79.5	°F Ta
73.7	°F Tf
------	% CO2
10.3	V Batt.
0.86	l/m Pump
------	% Efficiency
------	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:39:04 220.3 ppm
Fuel: Natur.gas

0.03	% Oxygen
221	PPM CO
2	PPM SO2
1	PPM NO
0.0	PPM NO2
1	PPM NOx
79.4	°F Ta
73.9	°F Tf
11.68	% CO2
10.2	V Batt.
0.86	l/m Pump
------	% Efficiency
0.1	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:44:48 220 ppm
Fuel: Natur.gas

-0.02	% Oxygen
0	PPM CO
0	PPM SO2
220	PPM NO
0.2	PPM NO2
220	PPM NOx
79.5	°F Ta
74.0	°F Tf
11.70	% CO2
10.1	V Batt.
0.85	l/m Pump
------	% Efficiency
-0.1	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.cleanair.com

ASSET #203120
Testo t350 XL
SN: 00844783 /USA
NONAME
09/12/03 12:51:20 90.5 ppm
Fuel: Natur.gas

-0.04	% Oxygen
0	PPM CO
28	PPM SO2
4	PPM NO
90.7	PPM NO2
95	PPM NOx
79.7	°F Ta
74.4	°F Tf
11.70	% CO2
10.1	V Batt.
0.84	l/m Pump
------	% Efficiency
-0.2	% Excess air
------	f/m Vel
------	inHg ΔP
------	inHg Draft

Heat transf.°F: --- °F
www.c[illegible]m

Testo 350 XL
Clean Air # 203120
09-12-03
Joe A

Emissions Test Results - September 17, 2003 (PAGE 4, Factory Calibration)

Factory
Calibration

```
------------------------
     ASSET #203120
     Testo t350 XL
SN: 00844783 /USA
------------------------
NONAME
09/15/03     11:36:03

Fuel: Natur.gas

 -0.03     % Oxygen
   0.0   ppm CO
     0   ppm SO2
 220.1   ppm NO
   0.0   ppm NO2
 220.1   ppm NOx
  76.0    °F Ta
  72.1    °F Tf
 11.70     % CO2
   9.7     V Batt.
  0.83   l/m Pump
------     % Efficiency
  -0.1     % Excess air
------   f/m Vel
------  inHg ΔP
------  inHg Draft
------------------------
Heat transf.°F: --- °F
------------------------
www.cleanair.com
```

220
NO(10%)

```
------------------------
     ASSET #203120
     Testo t350 XL
SN: 00844783 /USA
------------------------
NONAME
09/15/03     11:29:03

Fuel: Natur.gas

 -0.01     % Oxygen
 220.3   ppm CO
     0   ppm SO2
   0.0   ppm NO
   0.0   ppm NO2
   0.0   ppm NOx
  74.7    °F Ta
  73.2    °F Tf
 11.70     % CO2
   9.7     V Batt.
  0.83   l/m Pump
------     % Efficiency
  -0.0     % Excess air
------   f/m Vel
------  inHg ΔP
------  inHg Draft
------------------------
Heat transf.°F: --- °F
------------------------
www.cleanair.com
```

220
CO(10%)

Emissions Test Results - June 9, 2004 (PAGE 1)

Turbine Exhaust

Top of exhaust stack.

T

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 11:17:56

Fuel: Natur.gas

17.84	%	Oxygen
10	ppm	CO
22	ppm	SO2
6	ppm	NO
0.0	ppm	NO2
6	ppm	NOx
82.4	°F	Ta
570.8	°F	Tf
1.74	%	CO2
9.2	V	Batt.
0.91	l/m	Pump
38.5	%	Efficiency
478.4	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

T

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 11:20:50

Fuel: Natur.gas

17.82	%	Oxygen
18	ppm	CO
15	ppm	SO2
3	ppm	NO
0.0	ppm	NO2
3	ppm	NOx
79.8	°F	Ta
584.4	°F	Tf
1.75	%	CO2
9.2	V	Batt.
0.90	l/m	Pump
37.1	%	Efficiency
474.4	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

T

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 11:19:47

Fuel: Natur.gas

17.97	%	Oxygen
6	ppm	CO
4	ppm	SO2
3	ppm	NO
0.0	ppm	NO2
3	ppm	NOx
81.2	°F	Ta
578.7	°F	Tf
1.66	%	CO2
9.2	V	Batt.
0.89	l/m	Pump
35.2	%	Efficiency
501.2	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Turbine Exhaust

Through hole in exhaust stack above heat exchanger.

T

TESTO ASSET#202767
Testo t350 XL
SN: 00675788 /USA
NONAME
06/09/04 12:08:24

Fuel: Natur.gas

17.81	%	Oxygen
12	ppm	CO
2	ppm	SO2
3	ppm	NO
0.0	ppm	NO2
3	ppm	NOx
77.4	°F	Ta
596.6	°F	Tf
1.75	%	CO2
8.2	V	Batt.
0.92	l/m	Pump
35.7	%	Efficiency
473.0	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

T

TESTO ASSET#202767
Testo t350 XL
SN: 00675788 /USA
NONAME
06/09/04 12:07:31

Fuel: Natur.gas

17.85	%	Oxygen
2	ppm	CO
0	ppm	SO2
4	ppm	NO
0.0	ppm	NO2
4	ppm	NOx
75.8	°F	Ta
588.9	°F	Tf
1.73	%	CO2
8.3	V	Batt.
0.92	l/m	Pump
35.7	%	Efficiency
480.2	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

T

TESTO ASSET#202767
Testo t350 XL
SN: 00675788 /USA
NONAME
06/09/04 12:09:49

Fuel: Natur.gas

17.80	%	Oxygen
10	ppm	CO
2	ppm	SO2
3	ppm	NO
0.0	ppm	NO2
3	ppm	NOx
79.8	°F	Ta
598.8	°F	Tf
1.76	%	CO2
8.2	V	Batt.
0.92	l/m	Pump
36.0	%	Efficiency
470.9	%	Excess air
------	f/m	Vel
------	inHg	ΔP
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Desiccant Regen Exhaust

D

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 11:28:25

Fuel: Natur.gas

21.05	%	Oxygen
1	ppm	CO
0	ppm	SO2
0	ppm	NO
0.0	ppm	NO2
0	ppm	NOx
76.1	°F	Ta
95.7	°F	Tf
------	%	CO2
8.6	V	Batt.
0.91	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	Δp
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

D

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 11:26:25

Fuel: Natur.gas

21.06	%	Oxygen
0	ppm	CO
0	ppm	SO2
1	ppm	NO
0.0	ppm	NO2
1	ppm	NOx
77.2	°F	Ta
94.8	°F	Tf
------	%	CO2
8.7	V	Batt.
0.91	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	Δp
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Ambient

A

TESTO ASSET#202767

Testo t350 XL

SN: 00675788 /USA

NONAME

06/09/04 12:04:25

Fuel: Natur.gas

21.02	%	Oxygen
0	ppm	CO
0	ppm	SO2
0	ppm	NO
0.0	ppm	NO2
0	ppm	NOx
77.1	°F	Ta
73.2	°F	Tf
------	%	CO2
8.5	V	Batt.
0.91	l/m	Pump
------	%	Efficiency
------	%	Excess air
------	f/m	Vel
------	inHg	Δp
------	inHg	Draft

Heat transf.°F: --- °F

www.cleanair.com

Natural Gas Heat Content at Waldbaums Test of Capstone C60

Comparing KeySpan Utility Bills and Detailed Analytical Laboratory Readings

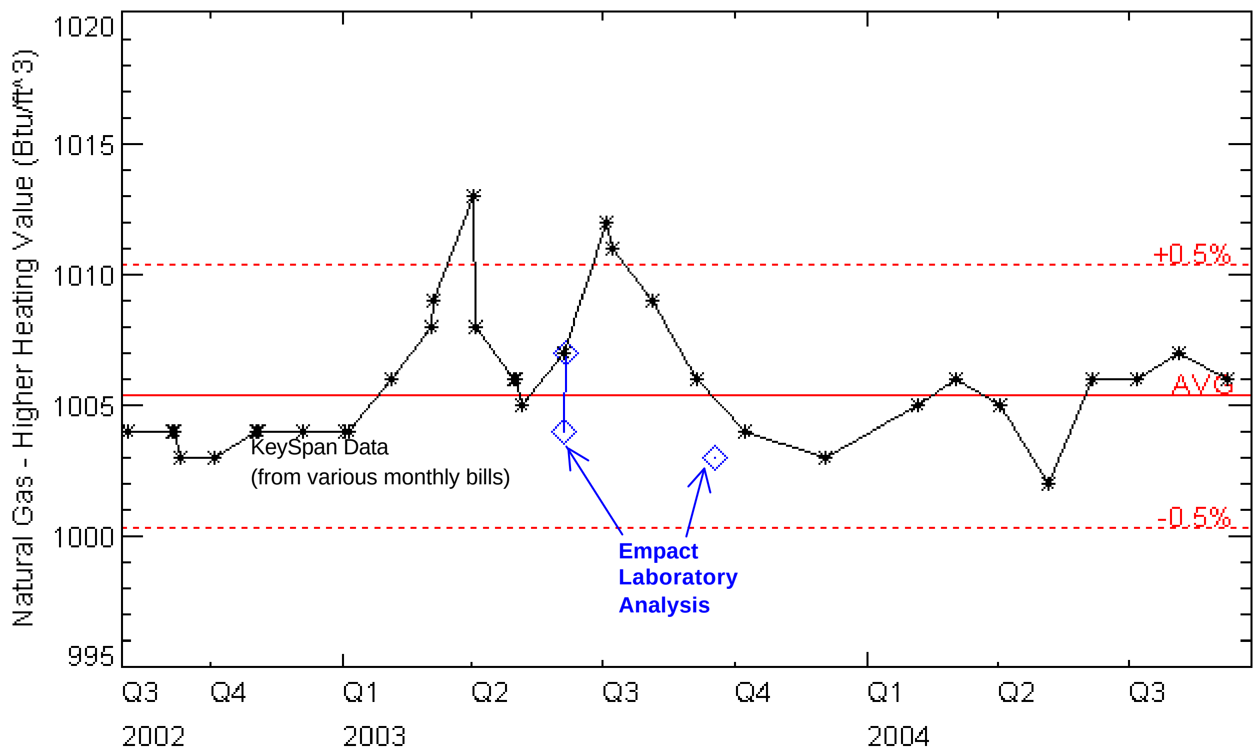
The Southern Research Institute (SRI) pulled samples of the natural gas for independent laboratory analysis by EMPACT ANALYTICAL SYSTEMS, INC. Ten gas samples were collected on during the June 4-6, 2003 test period. CDH repeated the process on September 17, 2003. The results from all the laboratory samples are summarized below. The individual data analysis sheets from Empact are given in the attached pages. The natural gas heat content, based on higher heating value, (a dry basis at 14.73) ranged from 1004 to 1007 Btu/ft^3 on June 4-6. In September the HHV was 1003 Btu/ft^3.

			HHV (Dry Real)		LHV (Dry Real)	
Test	**Date**	**SRI Run**	**@ 14.7**	**@ 14.73**	**@ 14.7**	**@ 14.73**
Page 1	JUNE 6, 2003	RUN 20 @ 0900	1,005.0	1,007.4	905.3	907.4
Page 2	JUNE 6, 2003	RUN 19 @ 0800	1,004.4	1,006.7	904.7	906.8
Page 3	JUNE 5, 2003	RUN 18 @ 1800	1,003.0	1,005.3	903.4	905.5
Page 4	JUNE 5, 2003	RUN 18 @ 1800	1,003.7	1,006.0	904.0	906.1
Page 5	JUNE 5, 2003	RUN 11 @ 1315	1,303.5	1,306.5	1,185.1	1,187.8
Page 6	JUNE 5, 2003	RUN 11 @ 1315	1,301.5	1,304.5	1,183.2	1,185.9
Page 7	JUNE 4, 2003	RUN 5 @ 1630	1,001.4	1,003.7	901.9	904.0
Page 8	JUNE 4, 2003	RUN 1 @ 1300	1,002.0	1,004.3	902.5	904.5
Page 9	JUNE 4, 2003	RUN 1 @ 1300	1,001.8	1,004.1	902.3	904.4
Page 10	JUNE 5, 2003	RUN 7 @ 1021	1,001.8	1,004.1	902.3	904.4

	@ 14.65	**@ 14.73**
SEPTEMBER 17, 2003	997.4	1,002.8

Note: Pages 5 and 6 (Run 11) are calibration runs with a known gas.

The plot below compares the laboratory analysis of the natural gas to the heat content reported by KeySpan on various utility bills. The KeySpan-reported value is typically within 0.3% of the measured value. Therefore we have used the time-varying value reported by KeySpan in our overall analysis. The red line shows the average of the KeySpan readings along with ±0.5% bounds. The seasonal variations are typically inside the ±0.5% bounds.



1020
1015
1010
1005
1000
995
Natural Gas - Higher Heating Value (Btu/ft^3)
+0.5%
AVG
-0.5%
KeySpan Data
(from various monthly bills)
Empact
Laboratory
Analysis
Q3
Q4
Q1
Q2
Q3
Q4
Q1
Q2
Q3
2002
2003
2004

APPENDIX F

DESICCANT AND AHU REPORT
FROM OCTOBER 2003
(REVISED JUNE 2004)

Summary of Desiccant and AHU Performance
Waldbaums - Hauppauge

This report focuses on the performance of the desiccant module in the Munters Air Handling Unit (AHU) that is installed at Waldbaums in Hauppauge, NY.

The desiccant module in the AHU treats a mixture of ambient and return air. Air entering the process side of the desiccant wheel is pulled from the central mixed air plenum before the DX cooling coil as shown in Figure F-1. Then the dehumidified process air from the desiccant wheel is returned back into the main plenum. A baffle on the entering side of the desiccant wheel ensures that most of the fresh air entering the unit flows through the desiccant module. When the desiccant module is off, fresh and return air flow directly through the DX coil (these flows are shown with dotted lines in Figure F-1).

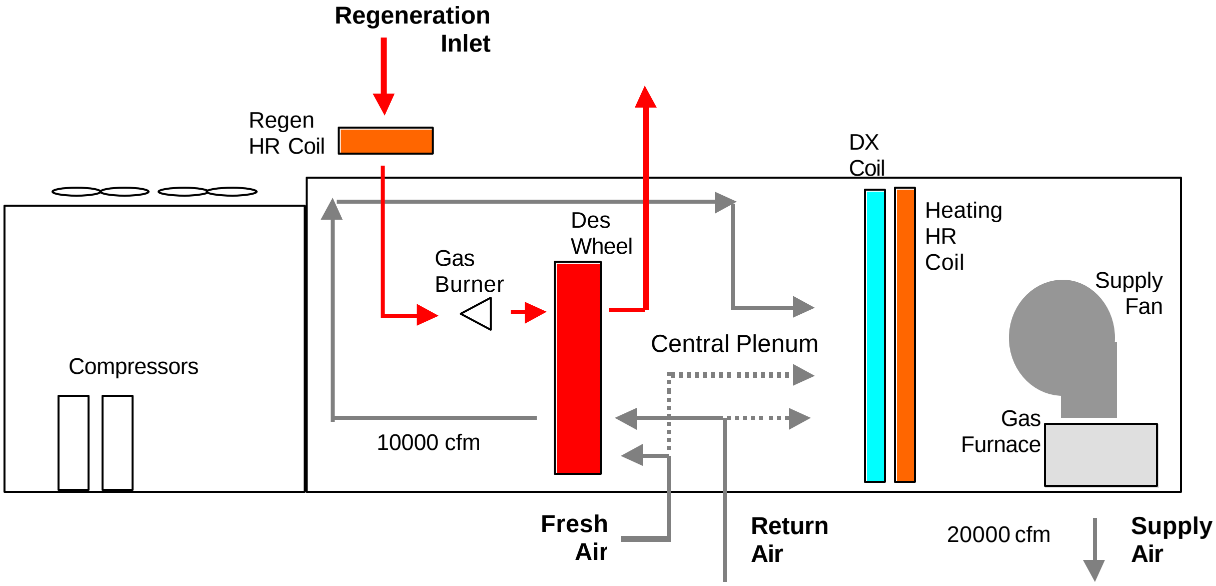


Figure F-1. Desiccant Unit Air Flow Schematic

Temperature, humidity and CO_2 sensors were installed at the locations shown in Figure F-2. The sensors were installed to measure conditions of the return, entering wheel process, and leaving wheel process air streams. The sensor for entering wheel conditions (TWE, RHWE) was located behind the filters as shown in Figure F-2. The location selected for the entering wheel sensors was found to be skewed towards the ambient conditions. The highly stratified conditions across the wheel made it difficult to find a suitable location for mounting these entering wheel sensors.

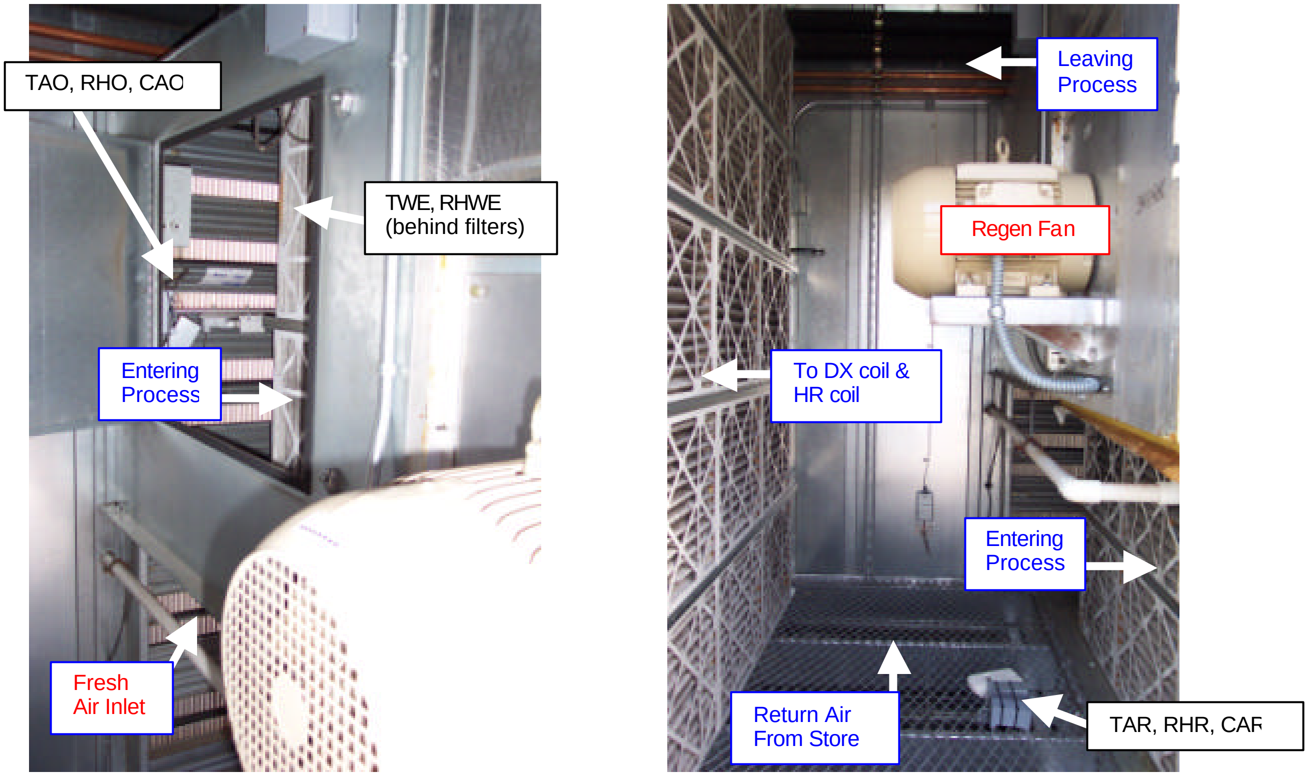


Figure F-2. AHU Central Plenum – Airflows Shown in Blue, Sensors in Black, Equipment in Red

Desiccant Wheel Operating Conditions

Handheld readings were taken with the TSI T/RH/velocity probe to estimate the actual entering wheel conditions in October-02 and July-03 (calibration sheets for the TSI are given in Appendix A). A set of readings were taken in the center of each of the ten 14 x 16 inch pleated filters covering the process section of the desiccant wheel (shown in Figure F-2). The resulting readings taken in October 2002 and July 2003 are shown in Figure F-3 and Figure F-4. There is significant stratification across the wheel. Return air enters at the bottom of the unit while the fresh air enters from the lower left hand side. The trends are most apparent with the data for July 2003, since the difference between ambient and return conditions were much greater that day. The flow-weighted average humidity level entering the wheel is 78.9 gr/lb. However the installed sensor reading (indicated by the dot in the figure) was 100.6 gr/lb. The conditions read by the installed sensors (TWE, RHWE) are significantly more skewed towards the ambient reading.

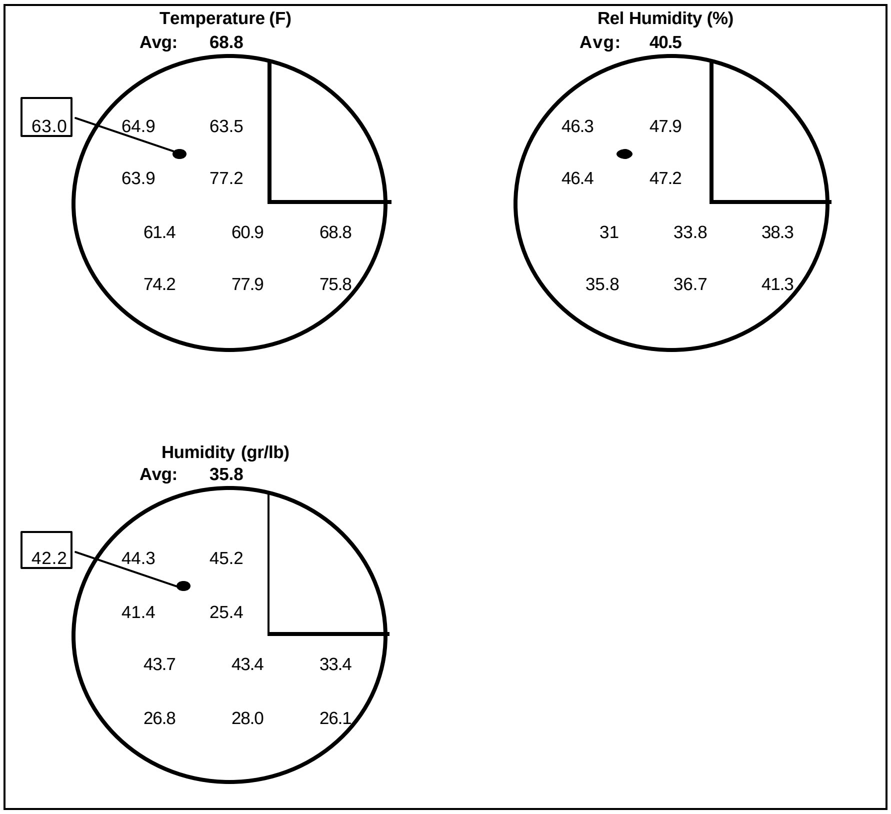


Figure F-3. Process Inlet Temperature, Humidity and Velocity Readings Taken in October 2003

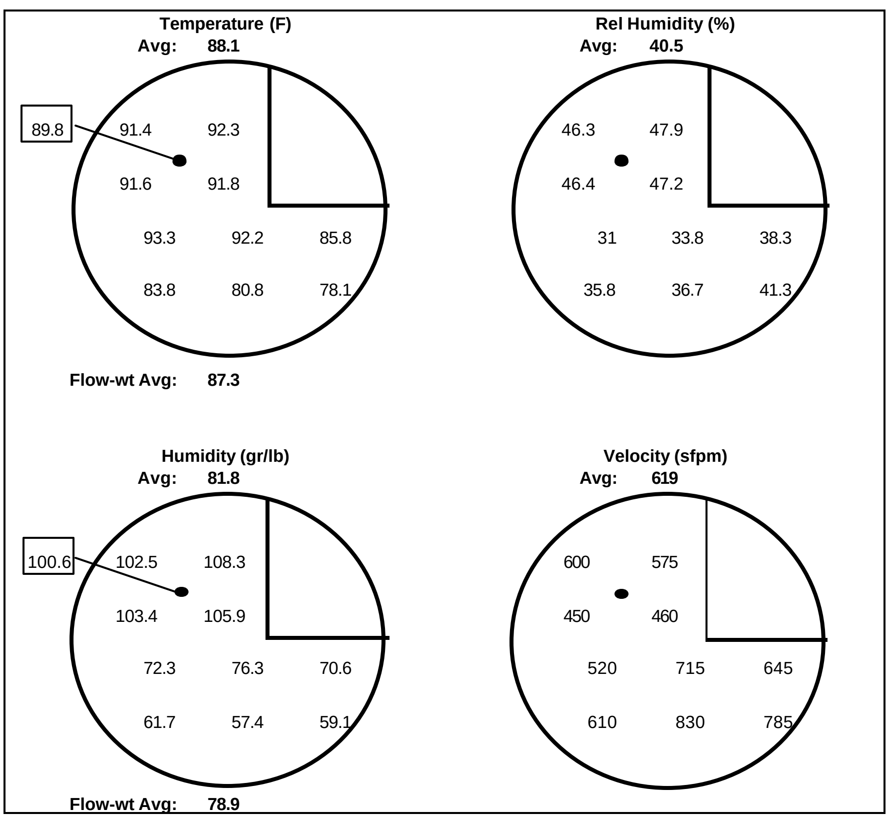


Figure F-4. Process Inlet Temperature, Humidity and Velocity Readings Taken in July 2003

Table F-1 summarizes the differences between the handheld readings of entering conditions and the measurements from the installed sensors. The installed sensor readings typically indicated that the entering conditions to the wheel were about 90% outside air (i.e., a 0.9 fresh air fraction). The average (and flow-weighted average) conditions from the TSI implied the actual fresh air fraction was closer to one half. The data from July 2003 implied fractions of 70% for temperature and 50% for absolute humidity. Data from October, when ambient-to-return differences were smaller and therefore less certain, implied a similar fraction.

Table F-1. Summary of Desiccant Wheel Stratification Measurements

		Measured Data (sensors)		Avg Entering Wheel		Flow-weighted Avg Entering Wheel	
Jul-03		Value	Fresh Fraction	Value	Fresh Air Fraction	Value	Fresh Air Fraction
Return	(F)	77.7					
	(% rh)	40					
	(gr/lb)	56.5					
Outdoor	(F)	91.7					
	(% rh)	47.1					
	(gr/lb)	105.3					
Ent Wheel	(F)	89.8	86%	88.1	74%	87.3	69%
	(% rh)	47.8					
	(gr/lb)	100.6	90%	81.8	52%	78.9	46%
Oct-02							
Return	(F)	76.9					
	(% rh)	15.6					
	(gr/lb)	21.3					
Outdoor	(F)	61.7					
	(% rh)	52.8					
	(gr/lb)	43					
Ent Wheel	(F)	63	91%	68.8	53%		
	(% rh)	49.5					
	(gr/lb)	42.2	96%	35.8	67%		

Therefore, instead of using the reading of entering conditions from the installed sensor, we have used the fresh air fractions derived above – 65% for temperature and 50% for absolute humidity – were used to estimate the entering conditions to the wheel.

Figure F-5 displays a psychrometric chart of the process air stream during periods of steady state operation. The plot only includes data records when ambient conditions were humid (i.e., greater than 115 gr/lb). The large diamond indicates the estimated entering wheel conditions (assuming fresh air fractions of 0.65 and 0.5 for temperature & humidity, respectively). The process leaving conditions are significantly above the wet bulb line, which implies the sensible heating of the process air is greater than the latent heat of vaporization. Using the average entering and leaving conditions, the sensible heating is 54% greater than the latent heat associated with the moisture removal.

The sensor calibration data in Appendix A implies the RH readings for the desiccant unit were most believable during the 2002 season. Therefore, Figure F-6 shows the same psychrometric analysis using only 2002 data (only 8 records from September 4 are used). The result was very similar. In this case the sensible heating was 57% greater than the latent heat of vaporization.

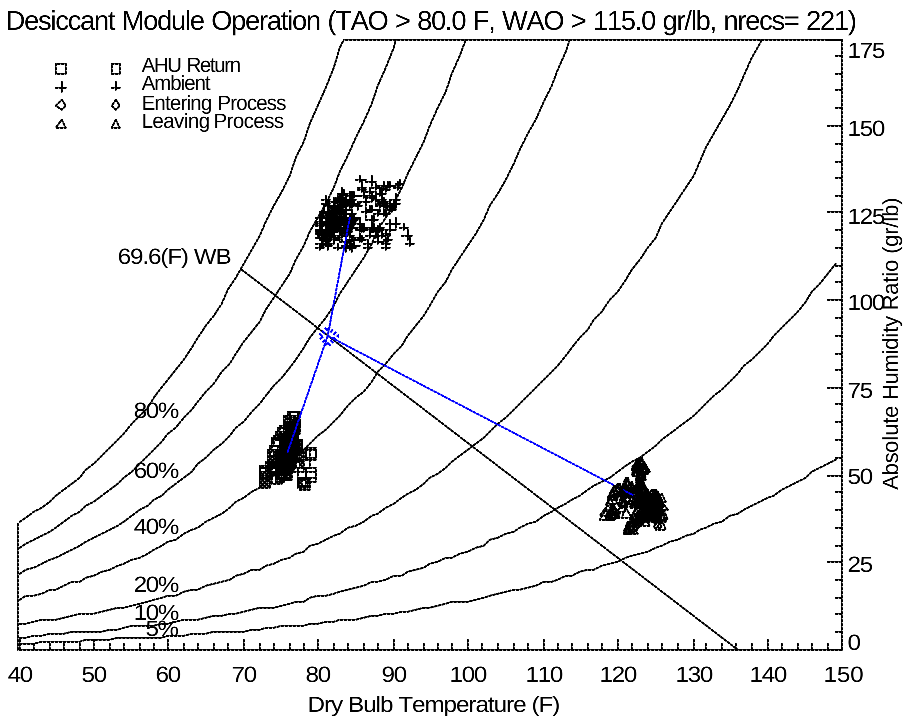


Figure F-5. Desiccant Process Shown on Pyschrometric Chart (all data)

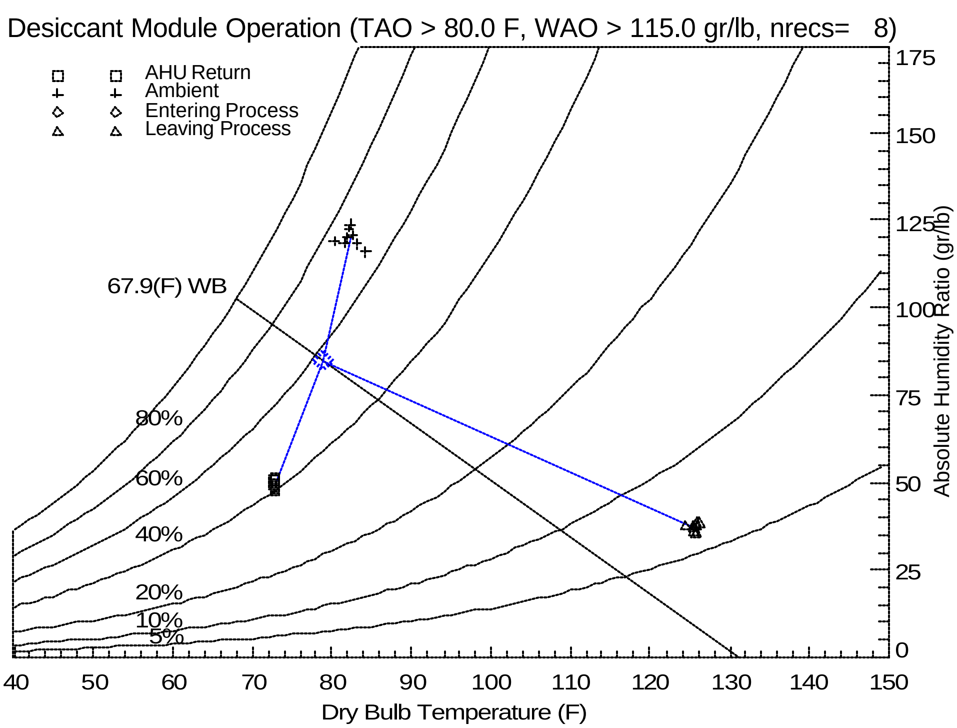
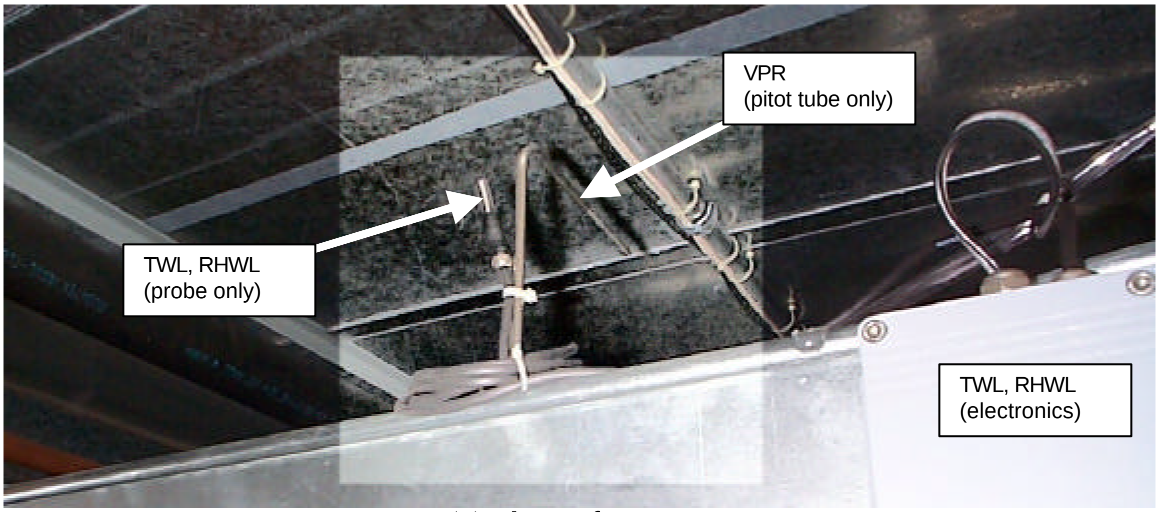


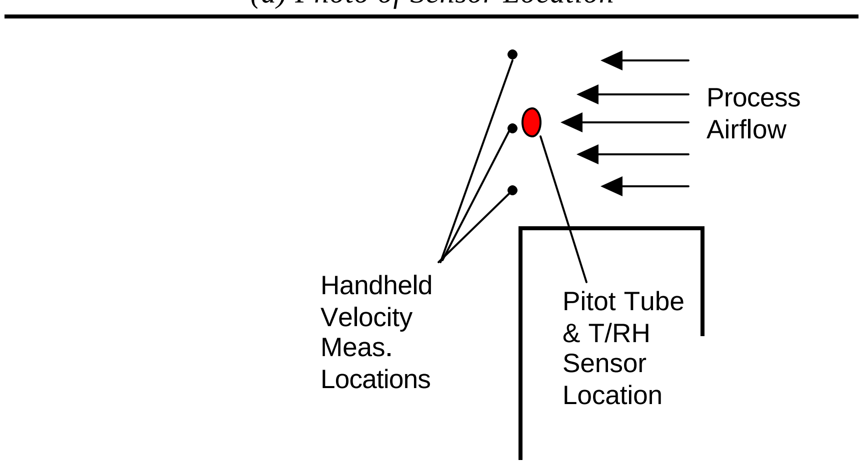
Figure F-6. Desiccant Process Shown on Pyschrometric Chart (2002 data only)

Process Airflow Measurements

A single pitot tube is placed in the center of the process outlet from the desiccant module to measure the center-line velocity of the airflow. Figure F-7 shows the location of the pitot tube and leaving process temperature/humidity sensor (TWL,RHWL). The sensors are located above the filter access door in the central plenum.



(a) Photo of Sensor Location



(b) Schematic of Sensor Location

Figure F-7. Process Leaving Sensors

The airflow is determined from the measured velocity pressure difference across the pitot tube:

$$SCFM = A \times 4005\sqrt{\frac{r}{r_{std}}} \times \sqrt{\Delta P}$$

Where:	A	=	cross sectional area of process outlet opening (42 x 16 inches, 4.67 ft^2)
	4005	=	constant for standard air conditions
	ρ	=	density for air at process outlet conditions

ρ_{std}	=	density for air at standard conditions (0.075 lb/ft^3)
ΔP	=	measured pitot tube pressure differential (in. WC)

The airflow computed from the pitot tube differential pressure is shown in Figure F-8. The flow rate predicted by the center-line velocity reading with the pitot tube averages about 8,100 SCFM. The data in Figure F-8 show that the measured velocity (corrected to standard conditions) was consistant across both summer seasons.

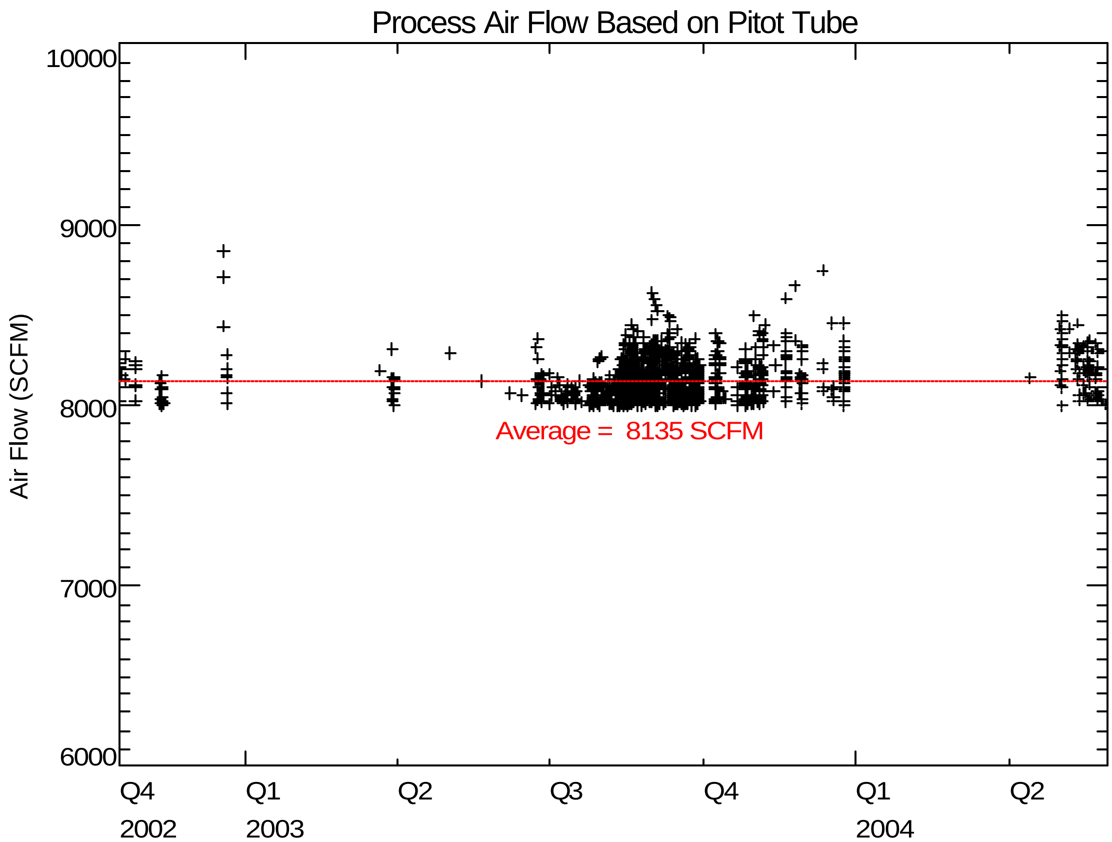


Figure F-8. Desiccant Unit Process Air Flow

Table F-2 summarizes the results of a 21-point velocity traverse in the same process air opening (see measurement locations in Figure F-7b) . The velocity measurements at each point from October-02 and September-03 are listed in Table F-2. The average flow rate determined from these readings was 10,200 scfm in October and 9,447 scfm in September. A multi-point velocity traverse was also taken in July 2003 and the average velocity was 2,010 sfpm, which corresponds to a flow of 9,380 scfm. The 2003 readings were most likely lower because the process air temperature was closer to the nominal operating point of 125°F, so the mass flow through the process side of the system is reduced[1]. In October-02 the process temperature was

[1] The process fan is a constant volume flow device, so the mass flow decreases as the air temperature through the fan increases.

much lower since the units was artificially forced to operate at dry conditions. The 2003 readings are probably most representative of normal operation.

Table F-2. Desiccant Process Air Flow Velocity Traverse (using TSI hotwire probe)

Process air flow		
Opening width	42	inches
Opening height	16	inches

Oct-02

	3"	9"	15"	21"	27"	33"	39"
2.5"	*2,450*	*2,650*	*2,820*	*2,650*	*2,380*	*2,450*	*2,650*
8"	*2,430*	*2,540*	*2,640*	*2,500*	*2,100*	*1,750*	*900*
13.5"	*2,360*	*2,450*	*2,500*	*2,450*	*1,800*	*1,000*	*620*

Average	*2,195*	*SFPM*
Area	4.67	ft^2
Air Flow	***10,242***	***SCFM***

Sep-03

	3"	9"	15"	21"	27"	33"	39"
2.5"	*2,270*	*2,530*	*2,530*	*2,360*	*2,410*	*2,470*	*2,420*
8"	*2,340*	*2,350*	*2,540*	*2,060*	*2,030*	*1,450*	*670*
13.5"	*2,240*	*2,190*	*2,310*	*1,960*	*1,640*	*1,220*	*520*

Average	*2,024*	*SFPM*
Area	4.67	ft^2
Air Flow	***9,447***	***SCFM***

A multi-point velocity traverse was also performed on the *inlet* the desiccant wheel (the readings are shown in Figure F-4). The average flow across the center of the ten 14x16 inch filters was 619 sfpm. So the approximate flow rate entering the wheel was 9,628 scfm. This flow entering the desiccant wheel would be expected to be slightly greater than the outlet due to the 400-600 scfm of purge air flow that Munters normally applies to their desiccant wheels. The differences between the inlet and outlet flow estimated from the TSI multi-point readings is consistent with this expected purge flow.

Table F-3 compares the estimated process airflow rates to the expected value of 9,000 scfm from the drawings. Excluding the readings from October-02, the estimated flow rates are all within 10% of the nominal value.

Table F-3. Comparison of Various Process Airflow Readings

Design/Nominal Process Airflow (from drawings)	9,000 scfm
Pitot Tube Measurement	8,117 scfm (-10%)
TSI Multi-Pt Velocity Traverse (Process Outlet)	
October-02	10,242 scfm (+14%)
July-03	9,380 scfm (+4%)
Semtember-03	9,447 scfm (+5%)
TSI Multi-Pt Velocity Traverse (Process Inlet)	9,628 scfm (+7%)

Using the average measured grain depression of 46 gr/lb across the desiccant wheel (from Figure F-5) and nominal process air flow rate of 9,000 scfm, the desiccant wheel is removing 265 lb/h of moisture, which is close to the nominal moisture removal capacity of 263 lb/h for the Munters unit listed on the drawings. Both the grain depression and overall dehumidification capacity are now more inline with the expected capacity of the system (in contrast to the initial estimates given in the interim report from December 2002).

Desiccant Module Regeneration Operation

Three thermocouples were installed to characterize regeneration performance: 1) entering regeneration burner (TRE), 2) leaving regeneration burner (TR), and 3) leaving desiccant wheel (TRL). A pitot tube was also installed to detect variations in the regeneration flow rate (VRG).

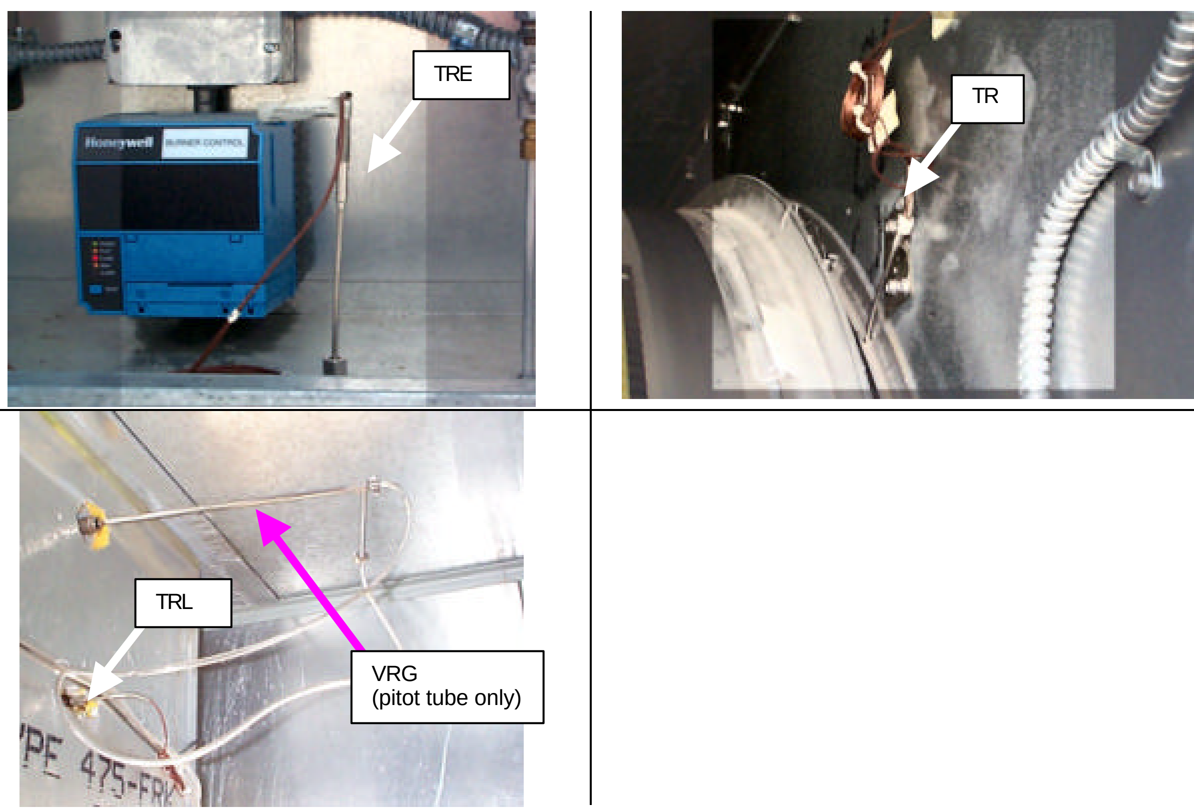


Figure F-9. Regeneration Sensors

The desiccant wheel is regenerated by a modulating, direct-fired natural gas burner that heats the regeneration air stream (TR) to about 280°F. The desiccant burner controls modulate the output of the regeneration burner to maintain a maximum 125°F leaving air temperature on the regeneration air stream (TRL). Typically more gas is required to maintain the leaving temperature when the entering process air is more humid.

Figure F-10 shows the operating temperatures and gas use for the desiccant module. The impact of heat recovery is shown in 2003. The heat recovery coil increased the entering temperature into the regeneration burner (TRE) to about 150°F. This decreased gas use by a nearly factor of two.

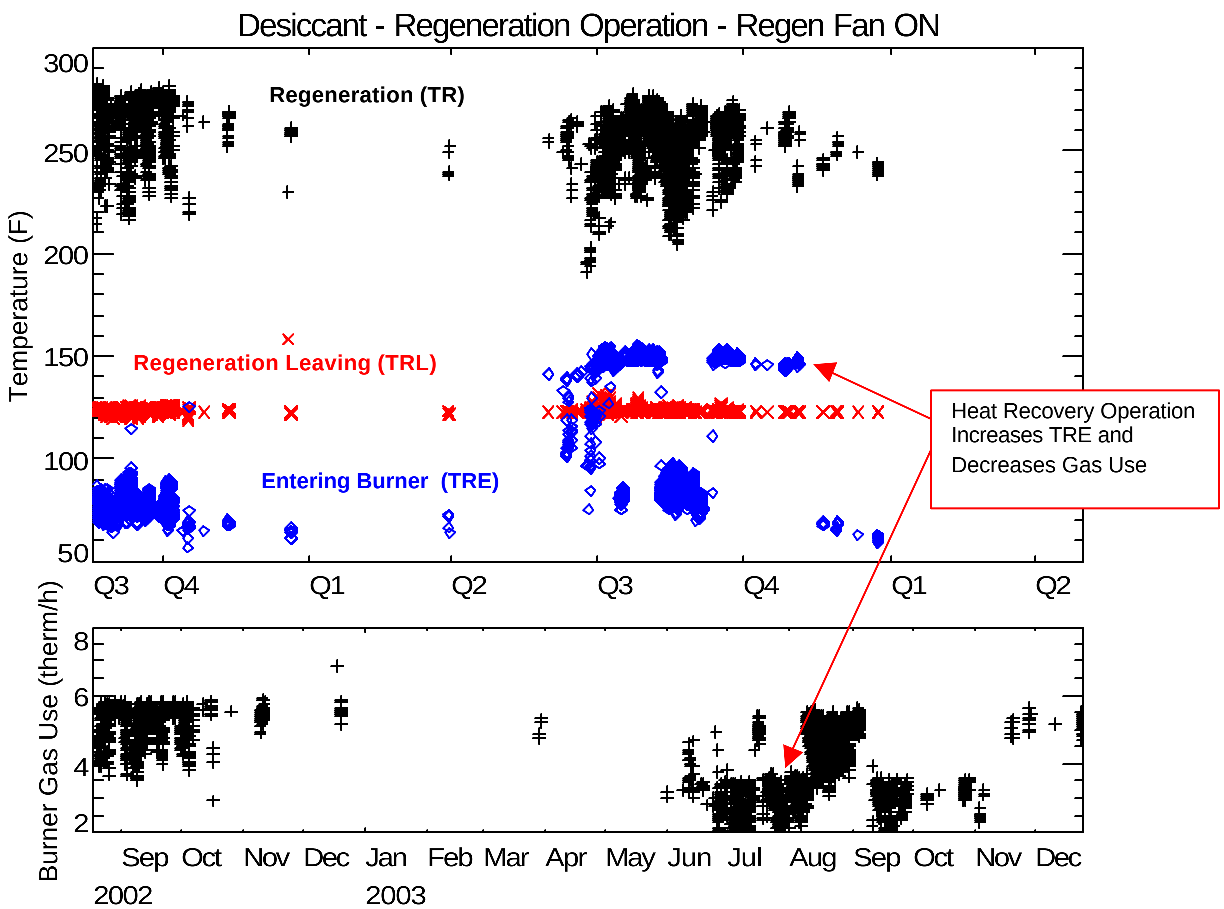


Figure F-10. Regeneration Temperatures and Gas Use (Regeneration Fan on for minimum of 15-minutes)

The burner gas input typically ranged from 4-6 therms/h at steady state conditions. Most of this variation was due to ambient temperature. Figure F-11 shows how burner gas use varies with the entering temperature. As ambient conditions are warmer, less gas is required to heat the regeneration air and maintain the leaving set point at 125°F.   Some of the variation in gas use is also explained by changes in the entering absolute humidity on the process side. More humid process air requires more gas use to maintain the leaving regeneration temperature.

The data also show that the regeneration burner was able to modulate down low enough most of the time when heat recovery was provided. A few minor exceptions are shown in Figure F-12. When heat recovery was provided on the hottest days, the burner had already modulated to minimum position and was not able to drop any further. As a result, the leaving temperature from the desiccant wheel could not be controlled and the temperature drifted above the set point by about 5°F for these few hours in July.

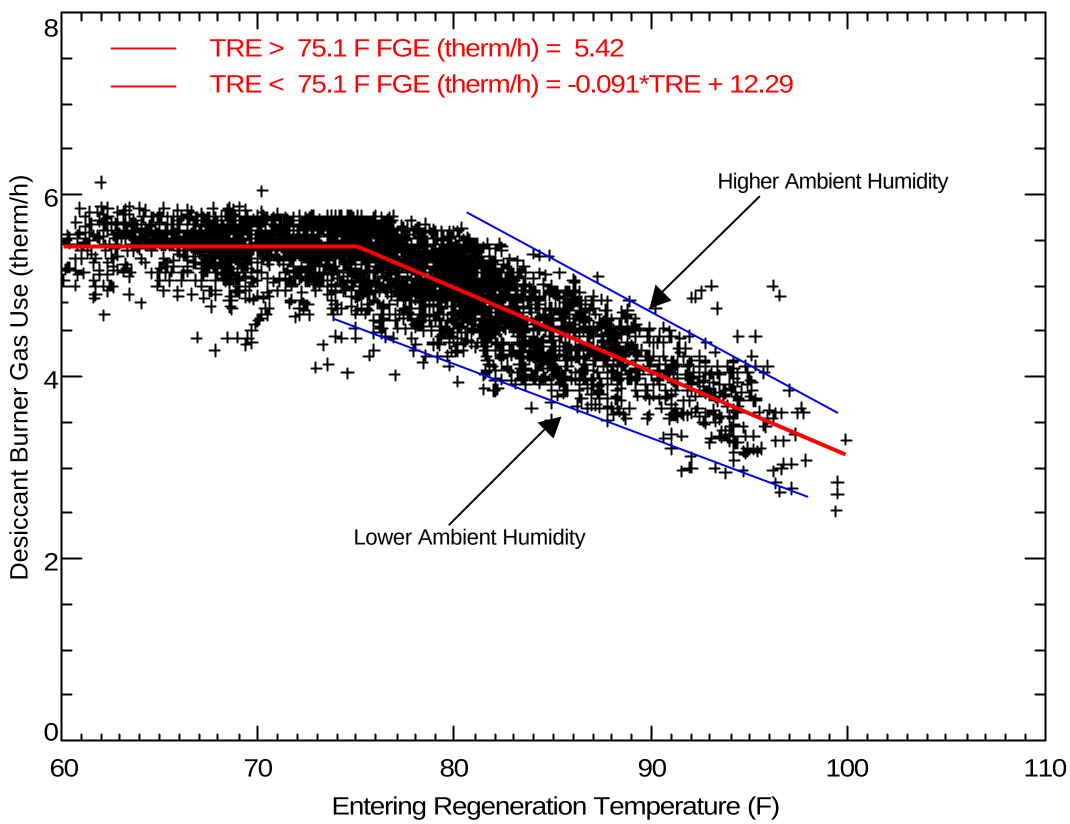


Figure F-11. Variation of Regeneration Gas Use with Entering Temperature (w/o Heat Recovery)

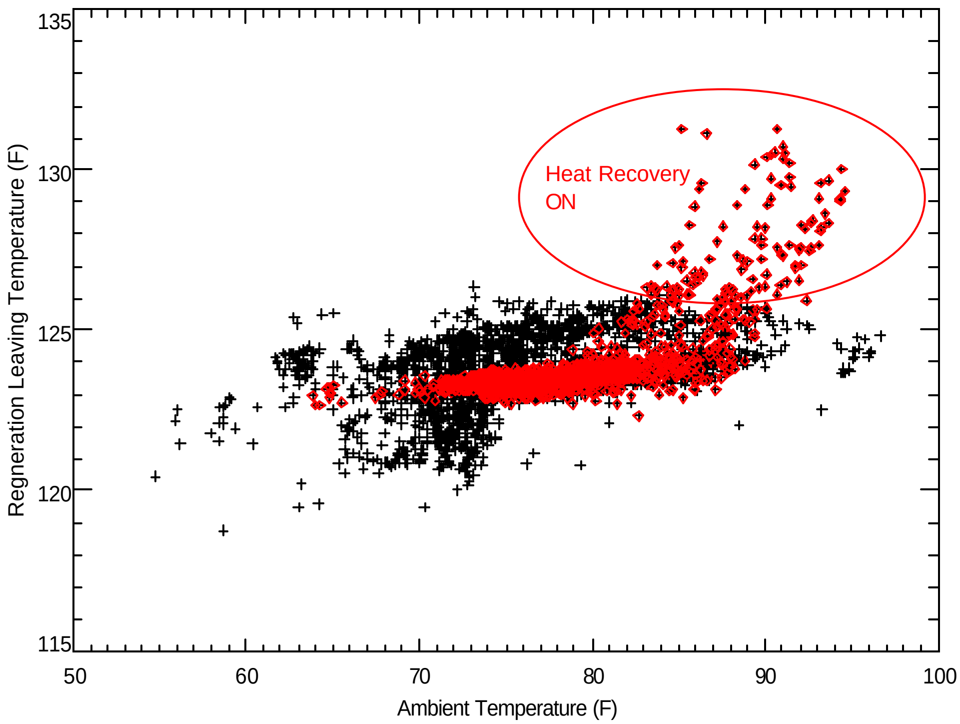


Figure F-12. Impact of Heat Recovery on Regeneration Burner Control

Several methods were used to estimate the regeneration air flow. The TSI velocity probe was used to complete a multi-point velocity traverse of the regeneration air stream at the exhaust opening on top of the unit. The traverse was performed in the same manner as the process air flow measurement, using the equal area method. The results of the velocity traverse are shown in Table F-4.

Table F-4. Desiccant Regeneration Air Flow Velocity Traverse (using TSI hotwire probe)

Regen air flow		Oct-02
Opening width	7.25 inches	
Opening height	11.75 inches	

	0.5"	1.5"	2.5"	3.5"	4.5"	5.5"	6.5"
1.5"	*8,250*	*8,800*	*9,000*	*9,500*	*9,250*	*9,650*	*9,900*
4.5"	*6,750*	*5,150*	*7,100*	*5,650*	*6,800*	*5,700*	*5,700*
7.5"	*3,600*	*3,500*	*4,810*	*1,440*	*1,810*	*1,330*	*1,100*
10.5"	*1,020*	*980*	*1,250*	*1,050*	*900*	*1,120*	*950*

Average	*4,716*	*SFPM*
Area	0.59	ft^2
Air Flow	***2,790***	***SCFM***

The velocity measurements on the regeneration outlet were repeated in July and a 16 point traverse indicated an average velocity of 5300 sfpm, and an air flow rate of 3,127 scfm.

The pitot tube was also installed to continuously track the regeneration flow. The pitot tube is located on the right hand side of the regeneration air stream, approximately halfway across the opening. The yellow shaded velocity readings in Table F-4 indicate the approximate location of the pitot tube. The results below show the velocity readings taken with the handheld probe at that location are in reasonably good agreement with the pitot tube velocities in Figure F-13.

The air velocity at standard conditions was determined from measured pressure difference using the equation below:

$$SFPM = 4005\sqrt{\frac{r}{r_{std}}} \times \sqrt{\Delta P}$$

Where:	4005	=	constant for standard air conditions
	ρ	=	density for air at regeneration outlet conditions
	ρ_{std}	=	density for air at standard conditions (0.075 lb/ft^3)
	ΔP	=	measured pitot tube pressure differential (in. WC)

To determine the air velocity in standard feet per minute (SFPM), the air density at the regeneration outlet must be calculated. Calculating the air density requires measuring the temperature and humidity.

Figure F-13 shows the calculated regeneration air velocity using the measured pitot tube pressure difference. Since the humidity level is not known, we have bounded the range of possible air flows using the density of air at the measured temperature and with assumed humidity levels of 0% and 100% RH. The average regeneration air velocity at the pitot is about 1,600 SFPM. This velocity agreed fairly well with the 1,440-1,810 SFPM determined for that location from the velocity traverse. The cause of the recent increase in regeneration flow rate for August-03 is not clear. The measured motor current on the regeneration fan did not show any variation with changes in air velocity (as would be expected if the air flow changed due blocked filters or slipping belts).

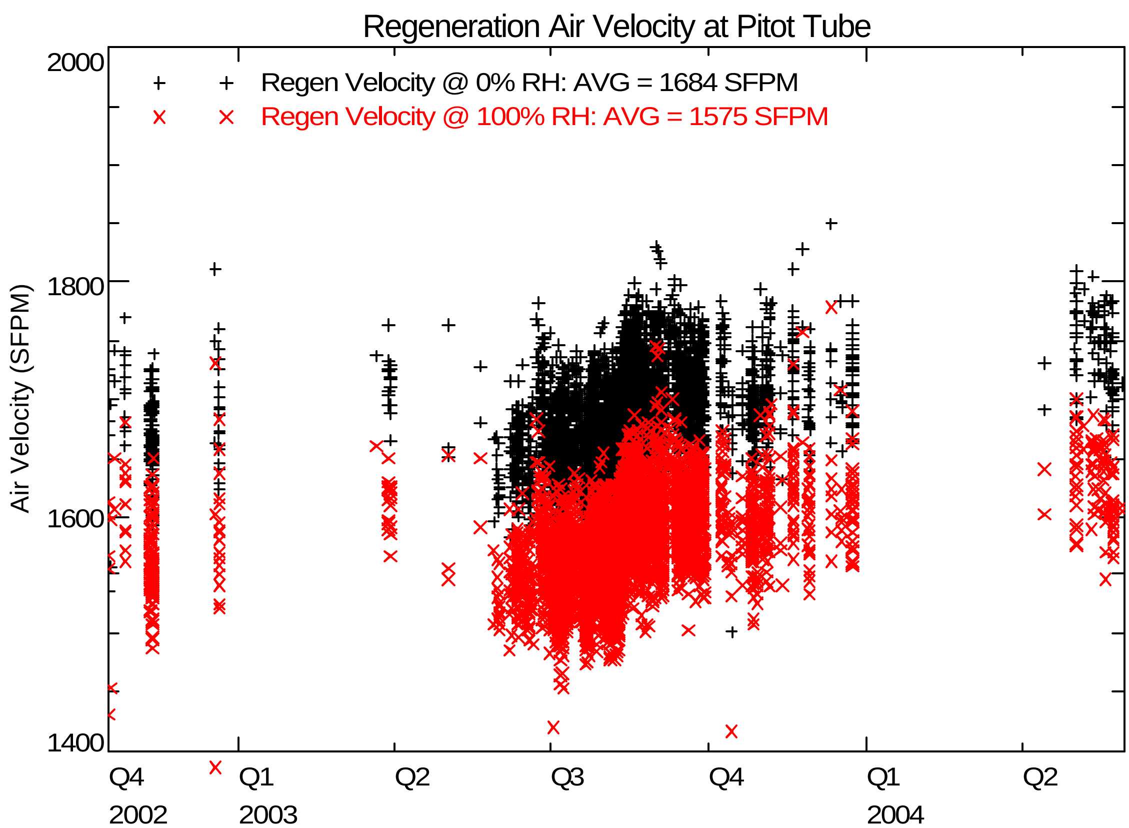


Figure F-13. Regeneration Air Velocity Measured by Pitot Tube

Another method of determining the regeneration air flow is to use the observed temperature rise across the regeneration burner and the gas input to the burner. Alternatively we can use the same technique with the heat added to the air stream by the heat recovery coil. To perform an energy balance across the burner we assume the burner efficiency is 95% (higher heating value). The heat content of the gas is based on the higher heating value reported on the site bills over the period (see Appendix E). These utility-supplied heat content values were confirmed by the one-time independent measurements taken by SRI on June 4-5 (i.e., 1007 Btu/ft^3) and by CDH on September 17 (i.e., 1002 Btu/ft^3).

The regeneration air flow is calculated by either:

$$CFM = \frac{Q_{burner}}{1.08 \times (TR - TRE)} \quad \text{or} \quad CFM = \frac{Q_{HR}}{1.08 \times (TRE - TAO)}$$

Where:

Where:	Q_{burner}	=	Energy output of the burner (assuming 95% efficiency)
	Q_{HR}	=	Energy added to air stream by regen coil (measured QHR – 20 Mbtu/h for losses)
	1.08	=	constant for air at standard conditions

TR	=	Regeneration temperature entering wheel (leaving burner)
TRE	=	Regeneration temperature entering burner (leaving HR coil)
TAO	=	Ambient Temperature (entering HR coil)

Figure F-14 displays the calculated air flow from the energy balance. The average regeneration air flow determined from a energy balance on the gas burner is 2,460 scfm. The flow predicted from the energy balance on the heat recovery coil is 2,638 scfm. Both of these values are consistent with the velocity traverse measurements.

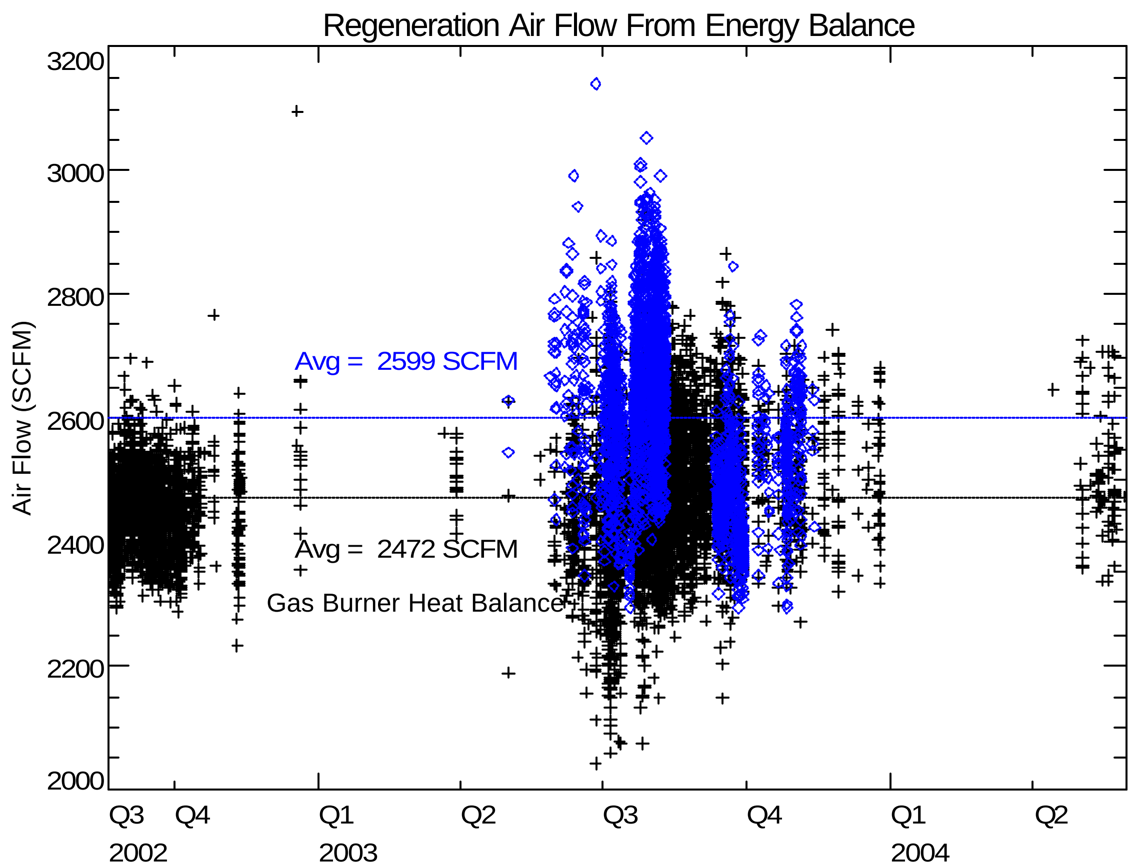


Figure F-14. Calculated Regeneration Air Flow From Energy Balance

Table F-5 compares the regeneration airflow rates predicted by the various methods. All the measurements were lower than the nominal rating of the unit (3,250 scfm). The air flow is probably lower than the design due to the addition of the heat recovery coil to the side of the unit. The add-on coil impedes the air flow and changes airflow characteristics compared to the standard Munters unit. This explains why the measured regeneration flow is about 20% lower than the nominal value.

Table F-5. Comparison of Various Regeneration Airflow Readings

Design/Nominal Regen Airflow (from drawings)	3,250 scfm
TSI Multi-Pt Velocity Traverse (Outlet) October-02 July-03	 2,790 scfm (-14%) 3,127 scfm (-4%)
Energy Balance on Regen Burner	2,460 scfm (-24%)
Energy Balance on Heat Recovery Coil	2,638 scfm (-19%)

Overall AHU Operation

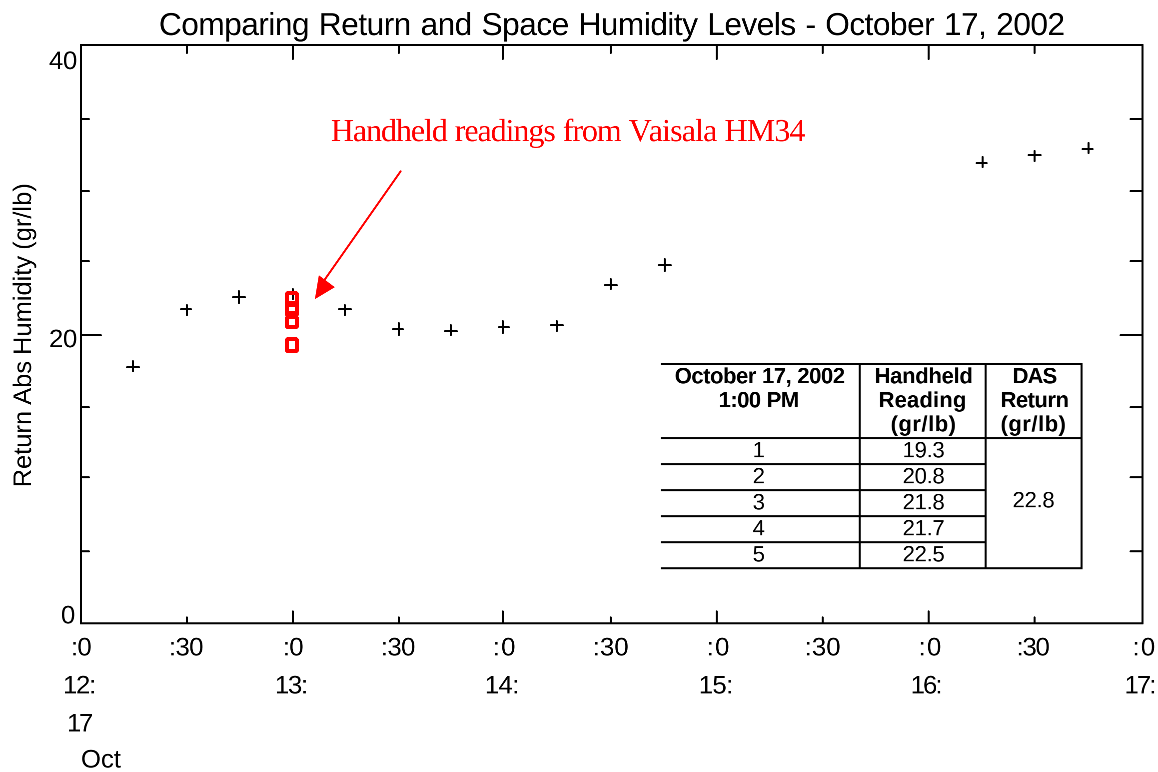
The Munters unit is the main air handling unit (AHU) for the store. It includes general heating and cooling sections in addition to the desiccant module. Other measurements taken on the AHU include the temperature entering the space-heating heat recovery coil (TCE) and the supply temperature, humidity, and CO_2 concentration (TAS, RHS, CAS). The supply air sensors were moved on October 17, 2002 because their original location on the back side of the fan was a found to be a poorly-mixed stagnation point. The new location for the supply air sensors is shown in left hand side of Figure F-15.

Figure F-15. Supply and Entering Heat Recovery Coil Sensors - Airflows Shown in Blue, Sensors in Black, Equipment in Red

Figure F-16. Closeup of Supply Sensors

<u>AHU Return and Space Conditions</u>

The AHU return conditions were shown to be very similar to space conditions. Five one-time measurements of space conditions were made from different areas in the store to evaluate the difference between humidity levels in the store and the corresponding return air conditions at the AHU. Figure F-17 shows that the handheld readings from the space agreed well with the return air sensor. The average space conditions were only 1.6 gr/lb lower than the measured return conditions.



October 17, 2002 1:00 PM	Handheld Reading (gr/lb)	DAS Return (gr/lb)
1	19.3	22.8
2	20.8	
3	21.8	
4	21.7	
5	22.5	

Figure F-17. Observed Sales Floor Humidity Readings and Corresponding DAS Reading (using TAR & RHR)

Figure F-18 displays the variation of return (or space) humidity levels with ambient humidity. The characteristic response shown here is consistent with the response we have observed in other dehumidified and cooled facilities. Even at peak ambient humidity levels the store is maintained below 50 gr/lb. During the winter, the store humidity approaches ambient conditions. At driest times the space humidity slightly exceeds ambient due to internal moisture generation from people, produce, and other sources. The relatively modest impact of internal moisture generation implies that the ventilation rate is high in this store (the high ventilation rate is confirmed in the section below).

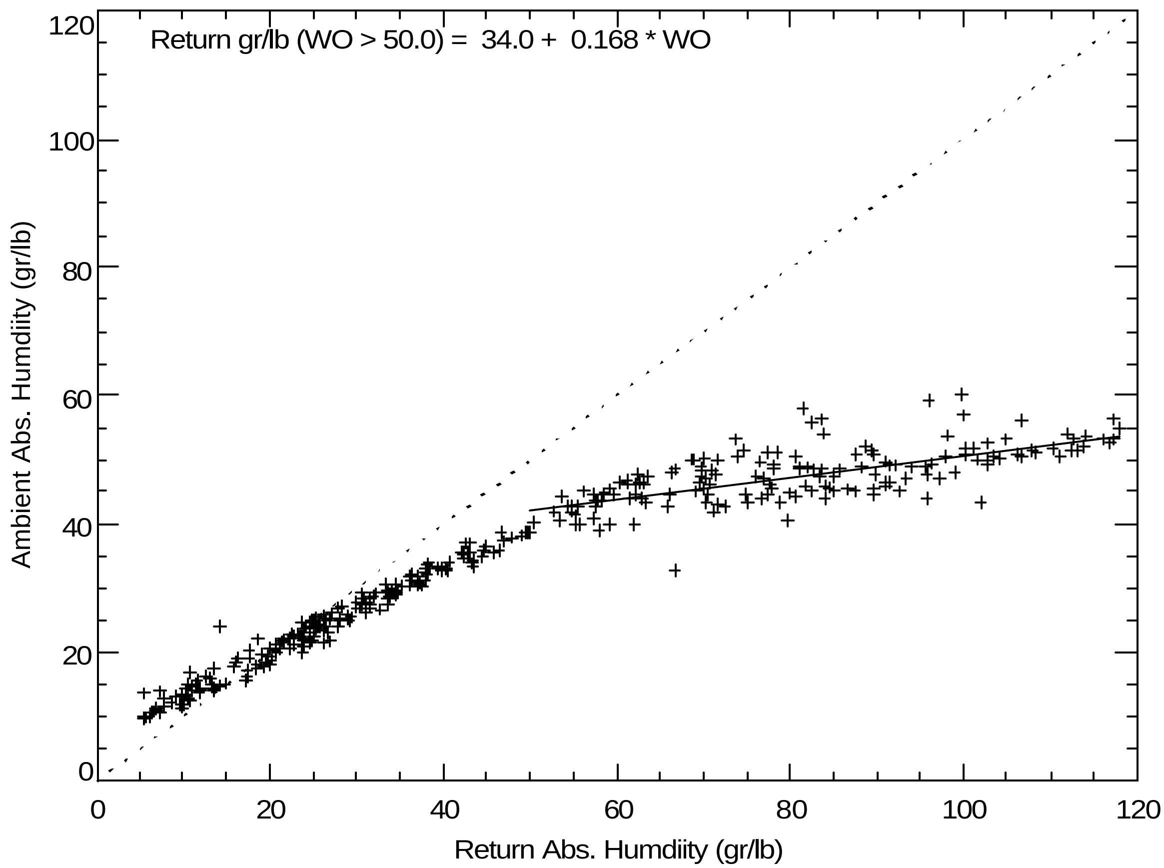


Figure F-18. Return Humidity Level Variation with Ambient

Figure F-19 shows the daily average return (or space) conditions on the psych chart. The dry bulb temperature was typically held at 73-75°F with only a slight difference between summer and winter operation. In the summer the humidity was always held below 40% RH. In the winter humidity levels typically drifted much lower. Since the space temperature set points are setup/setback at night, the daily average temperature drifted away from the occupied set points on cold and hot days. The hottest days on the psychrometric chart correspond to time that power was cut to the store.

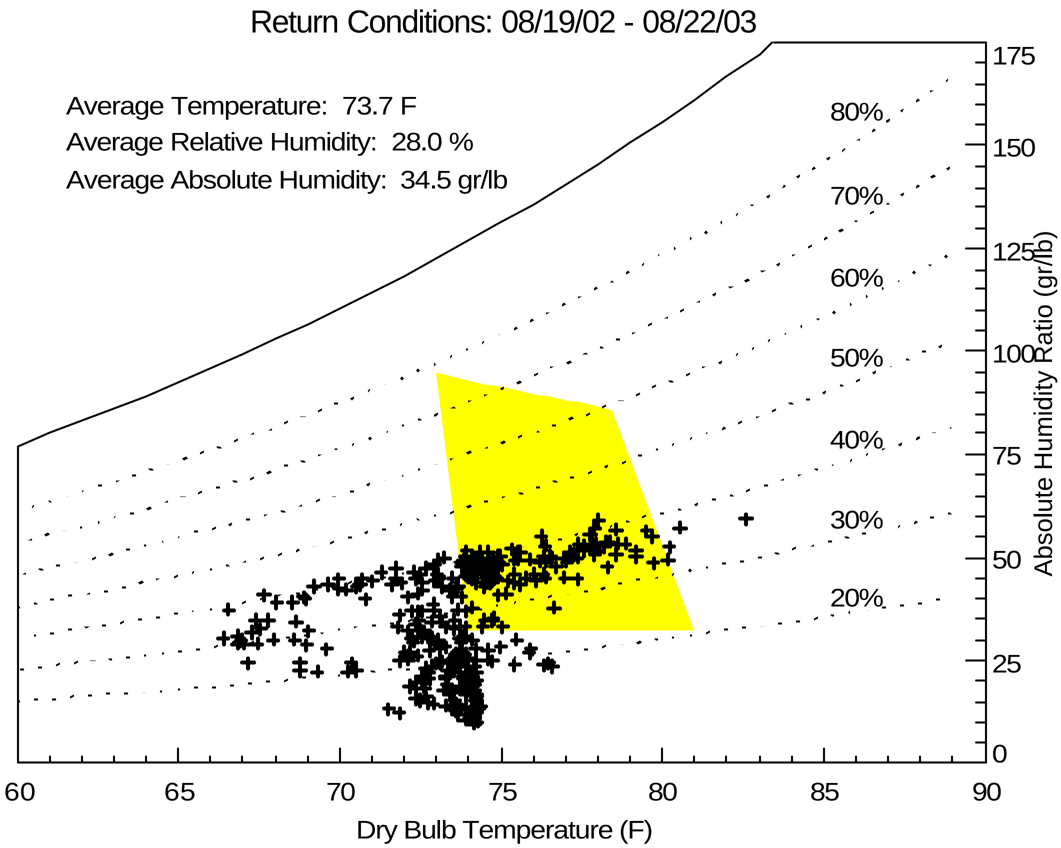


Figure F-19. Psychrometeric Chart of Daily Return or Space Conditions

AHU Supply Air Flow Rate

The supply air flow rate for the AHU was determined from an energy balance on the heat recovery coil installed inside the unit for space heating. By measuring the heat recovery rate (glycol side) and the temperature difference across the air-side of the coil, we could estimate the air flow rate. Since the heat recovery coil only started to operate after the end of the cooling season, there was not much normal heating data to choose from. Therefore, we have selected times when the heating coil was purposely or unintentionally forced to operate in the summer. The first time was on June 4 when the SRI testing was completed over a 4-6 hour period with the heat recovery coil forced on. The other time was on July 17, when the heating was mistakenly engaged by the control system. The predicted flow for both these times are shown in Figure F-20 and Figure F-21.

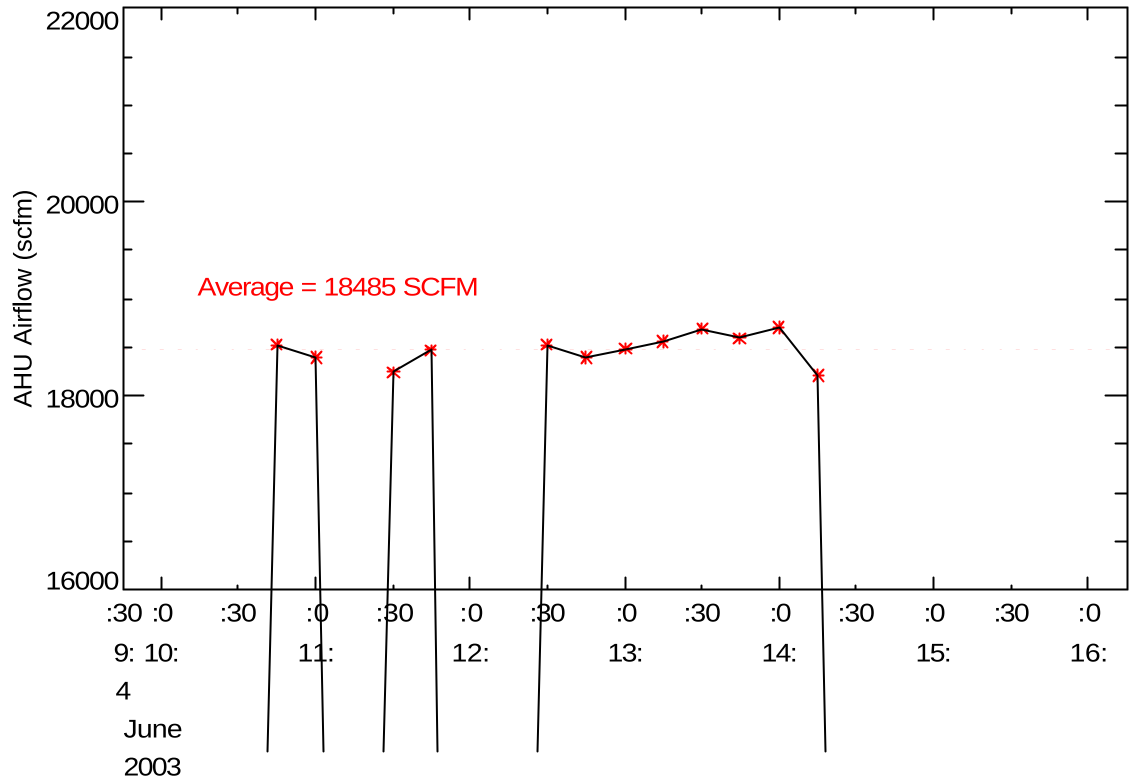


Figure F-20. Supply Airflow Rate Predicted by Heat Balance – Mid Afternoon, June 4

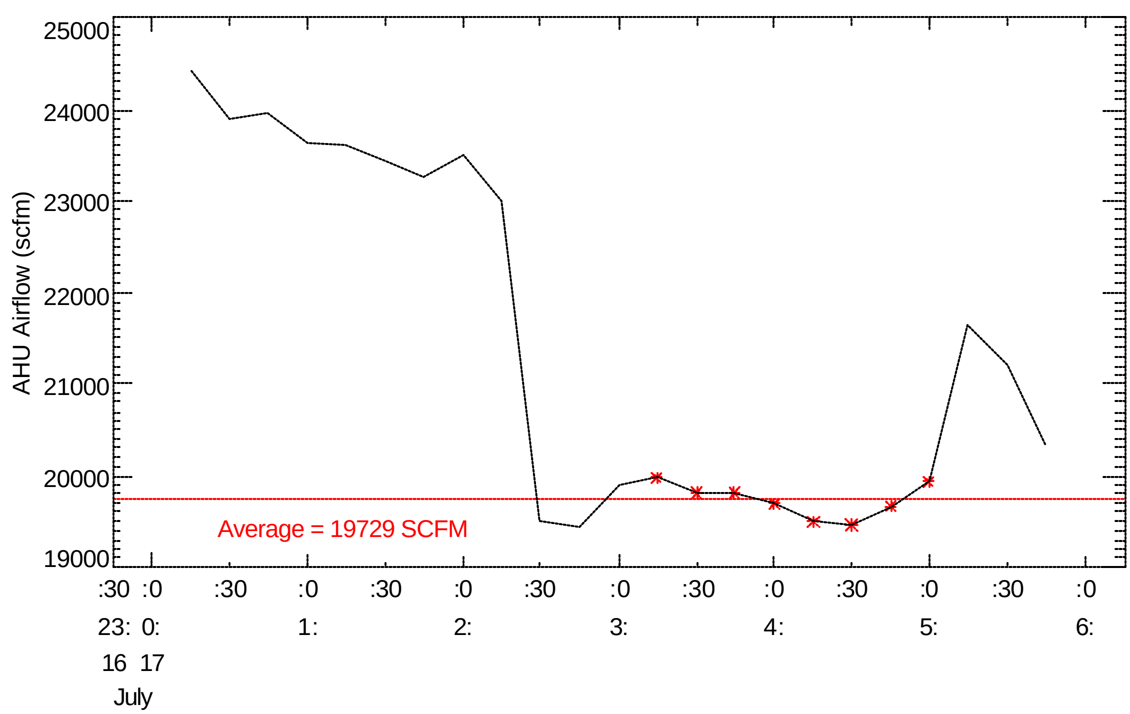


Figure F-21. Supply Airflow Rate Predicted by Heat Balance – Early Morning, July 17

Table F-6 shows that the flow rates predicted with this method are in reasonably good agreement with the nominal specifications for the system.

Table F-6. Comparison of Various Supply Airflow Readings

Design/Nominal Regen Airflow (from drawings)	20,000 scfm
Energy Balance on Heat Recovery Coil (Jun 4)	18,485 scfm (-8%)
Energy Balance on Heat Recovery Coil (July 17)	19,729 scfm (-2%)

AHU Ventilation Flow Rate

The approximate fresh air flow rate into the unit was directly measured by building a cardboard "Duct" around the fresh air intake opening, as shown in Figure F-22. The cardboard duct was temporality added to the intake in order to complete a velocity traverse by the equal area method. The 73 inch by 33 inch opening was divided into 36 equal area sections to take the flow measurement. Table F-7 summarizes the velocity traverse measurements. The measurements were taken twice on the morning of September 17. The second set of readings (Test 2) used a longer "time constant" on the TSI in order to damp out the wind-induced fluctuations that were observed for the first set of readings (Test 1). The two sets of flow readings imply the fresh air flow is 8,800 to 9,600 scfm, which is significantly higher than the flow of 5500 scfm specified on the drawings.

Figure F-22. Munters Fresh Air Intake with Cardboard "Duct" Added For Flow Measurement

Table F-7. Fresh Air Intake Flow Determined by Velocity Traverse (using TSI hotwire probe)

Fresh Air Intake Flow	
Opening width	33 inches
Opening height	73 inches

Sep-03
Test 1

	4.5"	12.5"	20.5"	28.5"
5.5"	850	730	680	480
13.5"	780	515	390	350
21.5"	575	500	420	300
29.5"	815	490	410	470
37.5"	900	490	410	420
45.5"	870	480	440	390
53.5"	825	600	420	460
61.5"	940	580	430	440
69.5"	900	825	530	520

Average	572.9	SFPM
Area	16.7	ft^2
Air Flow	**9584**	**SCFM**

Sep-03
Test 2

	4.5"	12.5"	20.5"	28.5"
5.5"	540	640	600	480
13.5"	350	490	440	350
21.5"	650	540	420	380
29.5"	900	440	385	300
37.5"	880	490	440	370
45.5"	650	530	480	320
53.5"	820	470	430	400
61.5"	820	560	480	440
69.5"	690	760	520	440

Average	524.9	SFPM
Area	16.7	ft^2
Air Flow	**8780**	**SCFM**

The fresh air flow was also confirmed by determining by from the fresh air fraction. Energy and mass balances utilizing temperature, moisture and CO_2 levels were used to estimate the AHU fresh air fraction. The equation below represents the resulting energy balance based on temperature. The fresh air flow rate is normalized by the supply air flow rate to yield the fresh air fraction (f).

$$TAM = f \times TAO + (1 - f) \times TAR$$

where:
TAO = Temperature of outdoor air
TAR = Temperature of return air
TAM = Temperature of mixed air stream (after the fan)
f = Fraction of the supply air stream from outdoors

Simplifying the equation to a simple, linear slope-intercept form yields:

$$[TAM - TAR] = f[TAO - TAR]$$

This equation can be used with measured data and regression analysis to find the slope, or fresh air fraction. Similar mass balances can be performed for moisture and CO_2 concentration. The results of these energy and mass balances are shown in Figure F-23. A duplicate temperature-based energy balance was performed the entering heat recovery coil sensor (TCE) in place of the supply air sensor (TAS).   Data shown are hourly averages, in order to eliminate scatter in the data.

The temperature-based fresh air fraction is the most reliable value now that we have data for both the winter and summer (i.e., we have a wide range of temperature differences). The absolute humidity data provide a somewhat reliable estimation of the fresh air fraction in 2002, even though it depends on two independent measurements (temperature and RH). However, since the RH sensors have been shown to have some long term drift in 2003 (see the calibration data in Appendix A) this fraction is not reliable. The fresh air fraction predicted by CO_2 was found to be an even less reliable and believable value due to the substantial long-term drift of these sensors.

The temperature-based fraction estimates that 48% of the supply air stream comes from outdoors. This is much larger than the fresh air fraction of 27.5% (i.e., 5500 scfm outdoor and 20,000 scfm supply) on the design drawings. However, it is in good agreement with the measured and inferred ventilation and supply flow rates presented above. The ventilation flow rate implied by the temperature-based fraction and the inferred supply air flow is about 9,500 scfm. This closely matches the airflow measurement from the velocity traverse above.

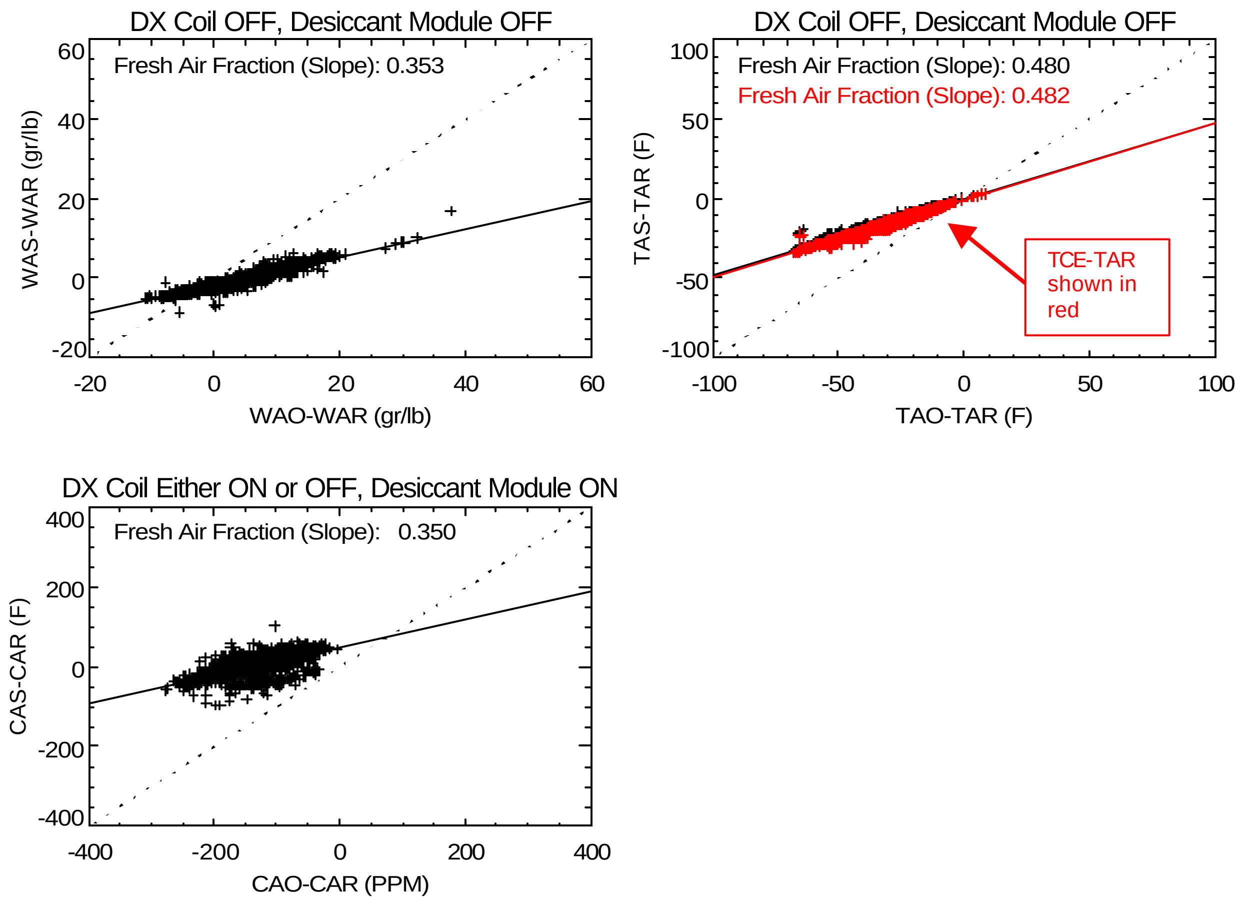


Figure F-23. Energy and Mass Balances to Determine AHU Fresh Air Fraction

APPENDIX G

UTILITY RATE DETAILS FOR SITE AND FOUR OTHER US LOCATIONS

Hauppauge (Test Site)

The microturbine at the store has its own gas service that is currently on Keyspan Rate 260 (High Load Factor Service). The natural gas rate includes transportation charges as well as commodity. Gas use for the rest of the store is currently on Keyspan Rate 170 (Space Heating) and applies to the Munters AHU gas service as well as the rest of the store. The schedule for both Rates 260 and 170 summarized in Table G-1 below.

Table G-1. Keyspan Gas Rate Schedules 170 and 260

Keyspan Gas

Rate 170 – Space Heating (store)					
Distribution Charges:	First 3 therms	Next 6 therms	Next 81 therms	Next 2910 therms	Over 3,000 therms
	$8.20	$1.0985/therm	$0.4676/therm	$0.3955/therm	$0.3289/therm
Rate 260 – High Load Factor (microturbine)					
Distribution Charges:	First 10 therms		Over 10 therms		
	$154.00		$0.130 therms		

Commodity Charges:[1]			($/therm)								
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$0.66	$0.63	$0.73	$0.80	$0.69	$0.71	$0.87	$0.82	$0.65	$0.64	$0.69	$0.68

[1] – Commodity prices estimated from the bills for 2002-2003.

The commodity price of gas varies based on the demand in wholesale markets. In recent years, the variation in commodity prices have been significant. For this cost analysis, the commodity cost of gas was inferred from the most recent gas bills for the microturbine (see the bottom of Table G-1).

The supermarket is currently purchasing power under LIPA Rate 285 (Secondary). The rate has three energy periods (peak, off-peak and intermediate) for peak demand and energy charges. There is also a service charge and meter charge per day. Table G-2 summarizes the electric utility rate.

Table G-2. LIPA Rate 285 Secondary Electric Charge

Monthly Charges	Secondary
Service ($/day)	$0.72
Meter ($/meter/day)	$0.23

Use Charges	Off-Peak	On-Peak	Intermediate
Demand Charge ($/kW)	none	$19.65	$4.68
Energy Charge ($/kWh)	$0.0629	$0.0877	$0.0770
Period	12am-7am	10am-10pm June-Sept	All Other Periods

Chicago

The utilities used for the Chicago location were Commonwealth Edison (ComEd) for electricity and Nicor for natural gas. The base supermarket electricity is provided under Rate 6 (General Service) while the CHP supermarket is billed under Rate 18 (Standby Service). The electric tariffs for Rate 6 and Rate 18 are summarized below.

Table G-3. Commonwealth Edison Rate 6 Schedule

Commonwealth Edison		
Rate 6 – General Service		
Monthly Service Charge:	$8.83	
Demand Charges:	Summer $14.24/kW	Winter $11.13/kW
Commodity Charges:	$0.06057/kWh	$0.04798/kWh
Applicable Periods:[1]	June 1 – September 30	Jan 1 – May 31, Oct 1 – Dec 31

[1] – Actual Summer period billed as "first monthly billing period with an ending meter reading date on or after June 15 and the three succeeding monthly billing periods"

Table G-4. Commonwealth Edison Rate 18 Schedule

Commonwealth Edison		
Rate 18 – Standby Service		
Monthly Service Charge:	$137.93 (500 to 1000 kW)	
Facility Demand Charge:	$2.99/kW of Facility Demand (500 kW used)	
Demand Charges:	Summer $15.16/kW	Winter $13.41/kW
Applicable Periods:[1]	June 1 – September 30, Mon-Fri, 9am-6pm	Jan 1 – Mar 31, Oct 1 – Dec 31, Mon-Fri, 9am-6pm
Commodity Charges:	On-Peak $0.05022/kWh	Off-Peak $0.02123/kWh
Applicable Periods:	Mon-Fri, 9am-10pm	All Other Hours

[1] – Actual Summer period billed as "first monthly billing period with an ending meter reading date on or after June 15 and the three succeeding monthly billing periods"

For gas service, the building is billed under Nicor Rate 4 (General Service). The gas tariff and historical commodity data were obtained from the utility.

Table G-5. Nicor Gas Company Rate 4 Schedule

Nicor Gas Company				
Rate 4 – General Service				
Monthly Meter Charge:	$50			
Distribution Charges:	First 150 therms $0.1330/therm	Next 4,850 therms $0.0683/therm	Over 5,000 therms $0.0377/therm	
Commodity Charges:	($/therm)			

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$0.69	$0.60	$0.83	$0.67	$0.63	$0.67	$0.67	$0.61	$0.58	$0.55	$0.58	$0.58

Southern California

The utilities used for Southern California were Southern California Edison (SCE) for electricity and Southern California Gas (SoCal Gas) for natural gas. The base supermarket electricity is provided under Rate TOU-8 (Time-of-Use General Service - Large). The same billing schedule was used for the supermarket with the CHP system installed. Under Applicability for the Self-Generation Deferral Rate (SSGDR), it states the co-generation facility must be larger than 200 kW. However, under the TOU-8 schedule, it states on page 8 a facility running parallel power generation must be billed under Schedule S (SSGDR). Be of this confusion, we used TOU-8 for both the base and CHP case. The electric tariff was obtained for TOU-8 and is summarized by the table below. The tariff has commodity charges for utility generation and Department of Water Resources (DWR) generation. The percentage supplied by each varies from month to month and no historical trends could be found. We assumed 50% of the commodity electricity came from Utility Generation (UG) and 50% from DWR for each month/

Table G-6. Southern California Edison Rate TOU-8 Schedule

Southern California Edison

Rate TOU-8 (Time-of-Use - General Service - Large)					
Monthly Service Charge:		$8.83			
Facility Demand Charge:		$5.22/kW (delivery)		$1.18/kW (Utility Generation[1])	
Max Rate:	$0.30221/kWh				
Demand Charges:	Summer On-peak	Summer Mid-Peak	Summer Off-Peak	Winter Mid-Peak	Winter Off-Peak
Delivery:	$6.88/kW	$0.59/kW	N/A	N/A	N/A
Utility Gen.:[1]	$10.67/kW	$2.21/kW	N/A	N/A	N/A
Total:	$17.55/kW	$2.80/kWh	N/A	N/A	N/A
Commodity Charges:					
Delivery:	$0.01579/kWh	$0.01579/kWh	$0.01579/kWh	$0.01579/kWh	$0.01579/kWh
Utility Gen.:[1]	$0.13499/kWh	$0.05355/kWh	$0.03419/kWh	$0.06552/kWh	$0.03521/kWh
DWR Gen.:[1]	$0.10287/kWh	$0.10287/kWh	$0.10287/kWh	$0.10287/kWh	$0.10287/kWh
Total:[2]	$0.13491/kWh	$0.09419/kWh	$0.08451/kWh	$0.10018/kWh	$0.08501/kWh
Max Rate:	$0.97677/kWh	N/A	N/A	N/A	N/A
Applicable Periods:	June 1 – September 30, Mon-Fri, 12pm-6pm	June 1 – September 30, Mon-Fri, 8am-11pm,	June 1 – September 30, All Other hours	October 1 – May 31, Mon-Fri, 8am-9pm	October 1 – May 31, All Other Hours

[1] – SCE bills for delivery, generation is provided either by SCE (Utility Generation) or by the Department of Water Resources (DWR). The percentage supplied by each varies from month to month.

[2] – Total Commodity Charges assumes 50% Utility Generation and 50% DWR Generation.

For gas service, the building is billed under SoCal Gas Rate GT-10 (General Service). The gas tariff and historical commodity data were obtained from the utility.

Table G-7. Southern California Gas Rate GT-10 Schedule

Southern California Gas

Rate GT-10 – General Service											
Monthly Meter Charge:			$1.48760/day[1]								
Distribution Charges:			First 250 therms[2]			250 - 4,167 therms[2]			Over 4,167 therms		
			$0.4102 per therm			$0.2255 per therm			$0.09221 per therm		
Commodity Charges:[3]			($/therm)								
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$0.54	$0.51	$0.64	$0.45	$0.47	$0.53	$0.50	$0.44	$0.48	$0.43	$0.39	$0.35

[1] – No Monthly Charge for Summer months (April 1 – November 30)

[2] – First 100 therms instead of 250 for Summer months (April 1 – November 30)

[3] – Commodity price for Oct 2002 - Sep 2003 from SCG website

New York

The utilities used for New York were Consolidated Edison (ConEd) for electricity and Keyspan for natural gas. The base supermarket electricity is provided under SC-9 (General – Large, Rate I) for both the base store and the CHP case (while the new standby rate SC-14 is now available exists (we were not able fully implement it). So we used SC9 for both cases.

Table G-8. Consolidated Edison SC-9 Schedule

SC-9, Rate I, General

		May	Jun	Jul	Aug	Sep	Oct-Apr
Demand Charges ($/kW)	All	17.79	17.83	20.74	19.77	19.81	20.6
Energy Charges ($/kWh)	All	7.85	8.26	9.27	10.32	10.15	8.53

Based on Consolidated Edison Rates for Summer 2003

For gas service, the building is billed under Keyspan Gas Rate 170 for Space Heating (summarized by **Error! Reference source not found.**). The microturbine gas service is billed under Keyspan Gas Rate 260 for High Load Factor (summarized by Table G-1).

Portland, OR

The utilities used for Portland were Pacific Power & Light (PPL) for electricity and Northwest Natural (NWN) for natural gas. The base supermarket electricity is provided under Rate 30 (General Service – Large Nonresidential) for delivery and Rate 200 (Cost-Based Supply Service) for electricity supply. The CHP Supermarket would receive delivery service under Rate 36 (Partial Requirements Service) and Rate 200 for supply.

Table G-9. Pacific Power & Light Rate 30 and Rate 200 Schedule

Pacific Power & Light

Rate 30 (General Service – Large Nonresidential Delivery) & Rate 200 (Cost-Based Supply Service)		
Basic Charge(Load Size>300 kW):	$260	
Load Size Charge:[1]	$0.55/kW	
Reactive Power Charge:[2]	$0.65/kVAR	
Transmission & Ancillary Charge:	$1.67/kW	
Demand Charges:	$2.51/kW	
Commodity Charges:	First 20,000 kWh	Over 20,000 kWh
	$0.0353/kWh	$0.0334/kWh

[1] – Load Size is based on the average of the two highest monthly demands for the previous year.
[2] – Power Factor is assumed to be 0.90 (the average observed during Waldbaum's monitoring)

Table G-10. Pacific Power & Light Rate 36 and Rate 200 Schedule

Pacific Power & Light		
Rate 36 (Partial Requirements Service) & Rate 200 (Cost-Based Supply Service)		
Basic Charge (Load Size>300 kW):	$260	
Standby Charge:	$2.09/kW[1]	
Load Size Charge:[2]	$0.55/kW	
Reactive Power Charge:[3]	$0.65/kVAR	
Reactive Energy Charge:[3]	$0.08/kVARh in excess of 40% kWh	
Transmission & Ancillary Charge:	$1.67/kW	
Demand Charges:	$2.51/kW	
Commodity Charges:	First 20,000 kWh	Over 20,000 kWh
	$0.0353/kWh	$0.0334/kWh

[1] – Standby Charge is calculated as 50% of the sum of the Transmission & Ancillary and Demand Rates times the difference between the maximum demand and the contract demand (500 kW)
[2] – Load Size is based on the average of the two highest monthly demands for the previous year.
[3] – Power Factor is assumed to be 0.90 (the average observed during Waldbaum's monitoring)

For gas service, the building is billed under Northwest Natural Gas Rate 31 (Non-Residential Sales). The gas tariff was obtained from the Northwest Natural website.

Table G-11. Southern California Gas Rate GT-10 Schedule

Northwest Natural Gas Company		
Rate 31 – Non-Residential Sales		
Customer Charge	$325	
Sales Charges:	First 2, 000 therms	250 - 4,167 therms
	$0.57050 per therm	$0.55549 per therm
Pipeline Capacity Charge:	$0.12779 per therm	