ENGINEERED MSW FUELS CAN REDUCE NOX AND OTHER EMISSIONS

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INTRODUCTION

A five year feasibility study was conducted using process modeling to design new fuels that could inherently reduce nitric oxides, sulfur dioxide and mercury emissions in power generation. The commercial station chosen for the study was a northeastern utility in Homer City with a history of emission difficulties. Heat data for the utility's unit 3 was available from diagnostic work done at this station back in the early 1980s.

Unit 3 has a pulverized coal (with CE Raymond Mills) balance draft steam generator with single stage reheat rated at 4,280,000 lb steam per hour. The Turbine is a 692 MW four valve unit operating in variable pressure mode. The unit utilizes two steam driven boiler feed pumps.

The company has been involved in a number of lawsuits over excessive emissions releases and has sought ways to successfully address the issue. New pollution abatement equipment coming on line at Homer City from various legal settlements has produced significant benefits.

In 1995, Homer City discharged 127383 pounds (57.780 metric tons) of SO2 [4].

In 1998, Homer City Generating Station produced a total (air and other) of 2,963 pounds (1,344 kg) of mercury according to the Environmental Working Group.

In 2001, a wet scrubber desulfurisation system for Unit 3 [2] was installed which enabled the plant to burn less expensive, higher sulfur coal, while still meeting environmental standards for sulfur emissions.

In 2012 General Electric assumed full control of Unit 3 hiring NRG energy services the following year to operate it. The Pennsylvania plant was in its second bankruptcy in five years [1] in legal actions resulting from excessive sulfur dioxide and other pollutant emissions.

In 2016 Homer City generated 11,287.9 tons SO2 and by 2017 just 4,904.2 tons of nitrogen oxides[5]

Homer City emissions modeling encompassed three phases.

The first phase was to complete development and integration of the earlier Homer city boilerturbine model commissioned under a *1985 Boiler Manufacturer* contract with assistance from a Virginia based research facility.

In 2001 General Electric bought the Homer City Generating station from Edison. In 2011 Edison failed to secure financing for pollution abatement equipment and transferred full control back to GE in 2012 who hired NRG energy, Inc to operate it.

Attempts to garner recent plant data from NRG personnel was not successful so Unit 3 equipment improvements were not modeled and system architecture remained at Homer City's original 1977 commissioning. Only the emission packages were upgraded and modeled. Figure 1 shows the plant architecture at the time of commissioning.

Figure 1- Unit 3
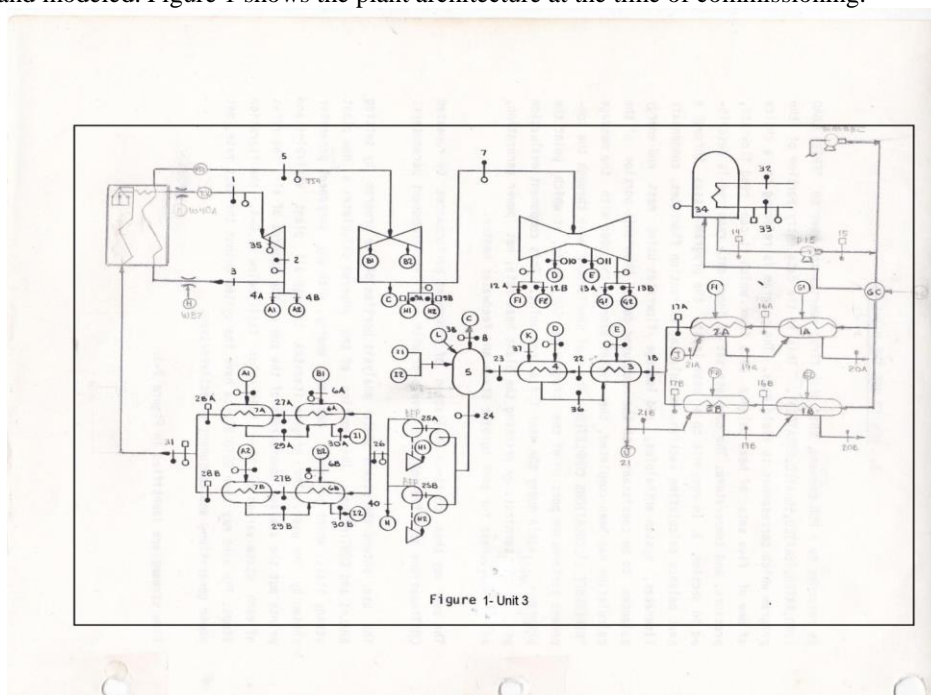
The second phase involved matching actual plant operation in terms of heat rate, megawatts generated, air, fuel and feed water flows along with equipment effectiveness to ensure predicted emissions were consistent with plant architecture.

The Unit 3 generating station consumes approximately 1.2[9] to 1.6 million tons of compliance coal per year. The plant purchases approximately 75% of this coal from one supplier and is mixed at a blending facility owned by the supplier. The remainder of the coal for Unit 3[2] is obtained in the spot market. Fuel consumption for Unit 3 from 1980 plant data amounted to 488,000 lbs/hr.

Since the coal ultimate analysis for Unit 3 at commissioning was not known an arbitrary coal reference fuel composition was developed with a high heating value (HHV) that best matched known post commissioning plant conditions. This reference composition was formulated in compliance with the general guidelines outlined in the *Ebasco Homer city system*

report [3] stipulating heat content of 10,900 – 12,700 Btu/lb, 12-23% ash and 1.4 - 2.8% sulfur respectively. The base coal reference HHV was found to be 13,000 Btu/lb.

A number of trials were necessary to determine the best fit of the plant's fuel consumption of 1,756,800 tons per year. Homer City fuel consumption is predicated on the assumption of 300 operating days per calendar year for the 1,756,800 tons of coal combusted Additional coal compositions were comparatively tested for emissions from a number of real sources.[15], [16]

The third phase was to determine the model plant performance when combusting reference coal to establish a base for emissions quantification. Mercury was set to 1998 reported levels in the emissions algorithm. Sulfur dioxide and nitric oxide levels were set to 2016 -2017 recorded plant data [5] in the coal reference from which all other fuels would be evaluated. From this performance point other coal compositions and specialty fuels could be evaluated for material suitability, economy, and performance and emissions burden. The engineered fuel ultimate analyses for these tests was prepared from EPA 2005 MSW data and various thermodynamic blends of shredded tires as depicted in Table One.

The engineered specialty fuels were designed with heat characteristics similar to Bituminous coals with the intent of reducing emissions. Typically a waste separation and handling facility recovers the recyclable materials before fuel pellet blending. Pellets can readily be manufactured to match coal heat content producing less NOx, sulfur and mercury.

Methodology

Key components of piping size, surface areas, quantity of tubes, material of construction, etc for the Boiler, Turbine, feed water heaters, and condenser were used in conjunction with heat balance data to define effectiveness factors for the hardware. Additionally performance factors were also defined for the two plant steam feed pumps to parameterize Unit 3 heat transfer relationships in the simulation.

The system model emulates combustion, generation and emissions of Homer City's Unit 3 692 MW power station. The simulation pairs a steady state *Newton-Raphson* Boiler algorithm with a *Forward Euler* Turbine-Feed water heater Extraction algorithm to assess balance of plant operations performance. The model utilizes an oxygen balance algorithm to estimate excess oxygen in the Furnace Exit Gas (FEG) and flue gas streams.

An iteration scheme can be devised to adjust the system variable states to find a solution set that satisfies mass and energy conservation constraints with the (i+1)th iteration given as:

$x_{n+1} = x_n + \aleph \, dt$ where $\aleph$ is the function derivative with respect to time

The resulting set of forward Euler equations tend to be stiff as some states respond more quickly than others. The stiffness can be reduced by transforming the system matrix of time derivatives about the design point to make the system linear:
$A \aleph = \lambda \aleph$ where λ is the eigenvalue of the system. Modifying the fundamental equation further gives
$\aleph^* = f(x^*) / \lambda$

This modification sets the eigenvalue equations equal to unity allowing for greater model step sizes. The eigenvalues are calculated as:
$\lambda = \partial x^* / \partial x$
For example applying these criteria to determine turbine extraction pressure at stage (P_o) for

a given feed water heater as a function of internal flow (w_1, w_2) gives:

$$\frac{dPo}{dt} = (w \quad - \quad w_1 \quad - \quad w_x)$$

The flow parameters are:

$$w = K_{b1} \sqrt{p_1 P_1 \, (1 - P_o/P_1)^2}$$

$$w_1 = K_{b2} \sqrt{p_0 P_O \, (1 - P_2/P_o)^2}$$ Where Kb1 and Kb2 are the velocity flow parameters

$$\frac{\partial (dP_O/dt)}{\partial p_o} = \frac{1}{2} \underline{Kb_1} [p_1 P_1 (1 - P_o/P_1)^2]^{-1/2} (-2) p_1 P_1 (P_o/P_1)^2 (-\frac{1}{2}) K_{b2} p_o P_O (1 - P_2/P_o)^2]^{-1/2} +$$

$$p_{o+} \qquad p_O \qquad \frac{(\partial p)}{(\partial po)} \qquad\qquad (1 \qquad + \qquad P_2/P_o)^2]$$

But $\quad p_o \quad \frac{(\partial p)}{(\partial po)} \quad$ is just equal to $\quad p_o,\quad$ so:

$$\lambda = \frac{\partial (dP_O/dt)}{\partial p_o} = - \frac{(Kb)^2}{w_1} p_1(p_o/p_1) - \frac{(Kb_1)^2}{w_2} p_o (1 + P_2/P_o)^2]$$

The same criteria are performed for each state variable to form a set of easily integrated equations.

These system equations can be set in a convergence scheme such that the square root of the sum of the squares of the ratios of the derivatives over their respective functions divided by the process elements approaches zero: i.e.:

$$\lim_{x \to 0} \sqrt{\frac{\frac{[T'(x)}{T(x)} \quad \frac{}{P(x)} \quad \frac{}{H(x)} \quad + \quad \frac{P'(x)}{} \quad + \quad \frac{H'(x)}{} \quad]}{E_{elements}}}$$

Expanding under the radical:

$$[(dT_n / T_n)^2 + (dT_{n+1}/ T_{n+1})^2 + (dT_{n+2} / T_{n+2})^2 + (dT_{n+2} / T_{n+2})^2 + ...(dT_{n+12} / T_{n+12})2] +$$

$$(dP_n / P_n)^2 + (dP_{n+1}/ P_{n+1})^2 + (dP_{n+2} / P_{n+2})^2 + ...(dP_{n+12} / P_{n+12})^2 +$$

$$(dH_n / H_n + (dH_{n+1} /H_{n+1})^2 + (dH_{n+2} /H_{n+2})^2 + (dH_{n+2} / H_{n+2})^2 + ...(dH_{n+12} / H_{n+12})^2]$$

9.0 E-5 was selected to represent the process simulation least squares zero point reducing error sufficiently to provide repeatable results. The number of functions is the number of process elements, so:

$$\lim_{x \to 9E-5} \sqrt{\frac{[...(dT_n / T_{n+12})^2 + ... (dP_{n+12} / P_{n+12})^2 + ... (dH_{n+12} / H_{n+12})^2]}{Elements}}$$

Emissions

NOx for the various fuel compositions was calculated based on the relationship derived in *CFD Modeling of Reduction in NOX Emission* [13]

$$\frac{d[NO]}{dt} = k_{pr} \quad [O_2]^b \quad [N_2] \quad [Fuel] \quad exp[-E_s /RT]$$

SO2 concentrations were determined from the standard second order kinetic model:

$$\frac{d[SO_2]}{dt} = k_p[S] \quad [O_2]$$

Where the reaction rate constant, k_p was determined from *Physical and Thermodynamic Properties of Elements and Compounds* [17]

The simulation includes two parameters to gauge predicted results. The first is a mass balance coefficient with (range 0 to 1) that indicates how well the model calculations conserve mass. The second is an energy balance coefficient (range 0 to 1) that indicates the degree of conservation of energy.

The mass entering and leaving the turbine forms the basis for determining the degree of mass conservation. A Mass Balance Ratio (MBR) is defined as the Steam flow entering the turbine - (sum of steam extractions (Wext), steam seal and gland condenser, etc to the feed water heaters) divided by the last stage turbine flow (WLP_{end}) which gauges mass conservation. For the coal base mass balance reference (MB):

MB = [W_{stm} - $\sum$ ($Wext_7$ +... DEA +...$Wext_1$)] / WLP_{end} where WLP_{end} is the model turbine calculated last stage flow.
= 2824702/ 2840121 = **0.9925** which indicates a good degree of mass conservation.

The Energy Balance ratio (EB) or efficiency sums the heat inputs and outputs across the entire plant. The ratio of outputs divided by inputs gives an indication of energy efficiency or consistency.
EB = $\sum$ (E_{out}) / $\sum$ (E_{in}) = 5.0847E09 Btu / 5.2635 E09 Btu = **0.966** which indicates an acceptable degree of energy conservation.

Fuel Blends

EPA's 2005 Municipal Solid Waste (MSW) composition table was the basis for fuel blending in Homer city Unit 3 tests. A typical waste composition form is shown in *Table 1. Municipal Solid Waste (MSW) Heat Content and Biogenic/Non-Shares, 1989 - 2005.*

Ten different MSW fuel blend formulations were developed with various fuel oxygen and nitrogen content using EPA 2005 MSW heat content and composition data as the fuel base mixed with various mass fractions of scrap tires to produce unique blends rich in fuel oxygen at specifiable heat content.

The ultimate analysis and heat content for the MSW blend components and scrap rubber was calculated by thermodynamic approximation [3] High heating values (Btu/lb) from calorimeter data were employed for coal when known otherwise the Dulong equation provided a satisfactory estimate. The Dulong equation was used for all MSW HHV estimates.

Fuel moisture includes the effect of humidity in combustion air. Table one shows the form of the composition analysis, heating values and costs per ton based on the chosen composition..

Table 1. Municipal Solid Waste (MSW) Heat Content and Biogenic/Non-Shares, 1989 – 2005

Sample	MSW	Tires	Composition		H -Btu/lb-mole	Moles
No	X= 0-8	(1-X)	C:	wt%	Btu/lb-mole	lb-moles
			H:	wt%	Btu/lb-mole	lb-moles
			S:	wt%	Btu/lb-mole	lb-moles
			O:	wt%		lb-moles
			N:	wt%		lb-moles
			H2O:	wt%		lb-moles
			Ash:	wt$		
Total						
Lbs	∑ X	∑ (1-X)	1.000		∑ Btu/lb	∑ lb-lbmoles
HHV	(Dulong)				Btu/lb	
Cost/ton					$/ton	

Results

Twenty tests were conducted consisting of ten bituminous coal and ten engineered fuel compositions with the resultant heat content calculated. Of these ten coal samples two were coalMSW blends. Additionally two of the coal formulations featured actual calorimeter heat content. All cases considered assumed complete combustion. All tests were performed at Unit 3 full load conditions of 4490000 lbs/hr feed water at 1000 °F superheat and reheat temperatures.

Table two quantifies the trade-offs and benefits in combusting engineered fuels. Coal tests are delineated by sample numbers 12_KY to 7 and the specialty fuels from 13 to 19.

Two coal samples 16-7525 and 17-7525 were blended to see how much sulfur content could be reduced without pre-treating the coal. Sample 16-7525 was blended with 75% Case 13 engineered fuel with 25% Case 7 coal lowering sulfur content from 3.7% to 3.05% by weight. This formulation was insufficient to reduce sulfur dioxide emissions below that of Case 7 coal.

Sample 17-7525 was a blend of 75% by weight Case 7 bituminous coal containing 3.7% sulfur with 25% EPA 2005 waste with 0.11% sulfur reducing the mix to 2.8% sulfur. The 17-7525 blend failed to reduce sulfur dioxide emissions below that of Case 7 coal and resulted in a much higher fuel cost at $2.42 per million Btu. However reducing excess air by just 0.61% in combusting the same blend lowered SO2 to 98.66 ppm versus 100.94 ppm at 15.1% excess air which is lower than Case 13 engineered fuel. Resulting NOx for these two cases of 17-7525 was lower than Case 7 at 0.92 ppm and 0.65 ppm respectively.

Modeling allows the plant to identify and correct environmental issues to increase EPA compliance and to customize fuels for optimum emissions reduction at lower cost.

Table 2 - Engineered Fuel Series Performance

Test	Fuel O2%	Fuel S %	Fuel N2 %	H2O %	NOxppm	SO2 ppm	XO2 %	Cost - $/10[6] Btu	Prim Air temp, ºF
12_KY	6.4	3.5	1.4	7.5	1.95	116.66	2.878	1.99	514
16-7525	9.4	3.5	1	3.4	1.66	123.24	2.382	1.5	514
17-7525	13.0	2.8	1.1	5.4	0.92	100.94	1.918	2.42	510
9a	9.7	1.8	1.6	1.3	3.33	51.33	4.124	2.03	516
VAT6-14	11.7	0.6	1.0	6.1	2.04	16.57	3.088	2.27	514
VAT1-15	5.6	0.6	1.4	2.9	4.63	19.1	4.306	1.73	519
11	5.2	0.8	1.4	0.1	3.69	18.69	4.328	2.02	516
8a-T5-9	6.7	2.3	1.5	2.5	2.59	76.3	2.644	1.75	517
10	1.5	1.8	1.9	1.4	3.57	51.24	4.473	1.78	517
7'	8.7	2.7	1.3	3.7	2.65	74.1	3.209	1.77	515
13	11.9	2.8	0.1	5.4	0.8	102.4	0.685	1.69	511
8	8.3	3.1	0.1	7.8	1.32	104.1	1.415	1.69	513
6	19	1.4	0.2	5.3	0.56	61.4	0.148	2.07	510
4	13.4	2.4	0.1	7.8	0.97	88.3	0.891	2	512
2	16.5	1.8	0.2	7.4	0.69	75.9	0.364	1.98	512
1	19.1	1.3	0.2	7.1	1.4	66.0	0.698	1.96	519
5	18.4	1.5	0.2	7.2	0.79	76.4	0.272	1.67	517
3	19.4	1.3	0.2	7.1	0.8	61.2	0.345	1.97	515
18	14.8	2.4	0.1	6.8	0.5	97.22	0.101	1.66	510
19	17.8	1.9	0.1	8.1	0.56	88.09	0.1	1.62	514

Standard unit 3 plant operations for coal is 19+ percent excess air; however air levels typically must run 20% to 24% for engineered fuels with carbon content below 60% in order to make 1000 ºF reheat temperature. The specialty fuels have significantly higher oxygen content than coal so engineered fuel consumption averaged 17.5 % more to produce equivalent power. However greater MSW based fuel consumption is desirable to rid municipalities of non-recycled waste. Figure 1b shows the engineered fuel quantities consumed and unit megawatts generated. The 655.1 MW average shown in green is about a quarter percent variance from actual Unit 3 656.8 MW operations.

The model predicted Unit 3 base fuel consumption of 5938.2.tons/ day or 1,781,460 tons yearly, is within 1.4% of actual plant post commissioning consumption. Lower combustion air temperatures for the suppression of NOX increased specialty fuel consumption across the series and in cases 1, 3 and 19 stretched existing coal handling capability beyond adequate reserve capacity.

Fig 1b - Unit 3 Predicted Combustion Characteristics MSW-Blend Fuels
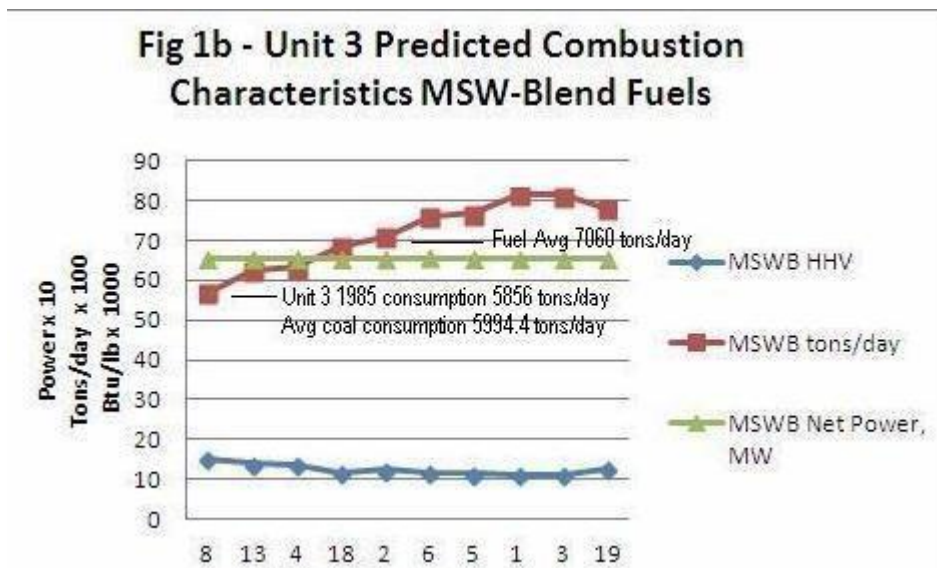
Model compatibility

The predicted heat rate for the Unit 3 coal reference was 10,251 Btu /Kwh versus Homer city's 10,183 Btu /Kwh. which is less than 1 % variance.

Cycle efficiency for the coal reference was 33.30% compared to the plant's 33.53% which is less than one percent.

Furnace bank absorbance for both coal and engineered fuels was held constant at 99% along with the economizer and air heater banks each at 98%. The Platen Super heater absorbance was constant at 84% for both fuel series. Secondary superheat bank absorbance varied from 84% to 90%. The higher hydrogen content in engineered fuels played a significant role in bank absorbance differences.

Primary super heat absorbance varied from 91 to 94%. Secondary Reheat absorbance was typically 92 to 94 percent while primary reheat bank absorbance varied from 95% to 97%. Fig 1c shows the average bank absorbance's for the two fuel series.

Fig 1c - Boiler Bank Absorbance Eng Fuel vs Coal
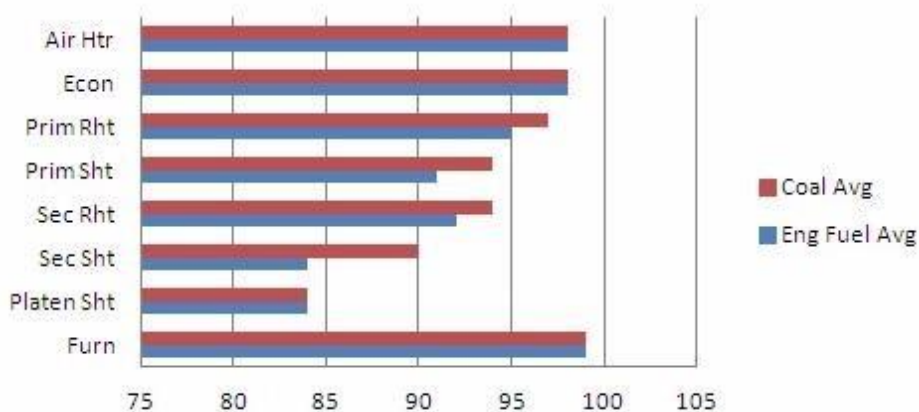
The balance of plant performance factors for the Turbine, feed water heaters and boiler feed pumps was unchanged with engineered fuel use.

Boiler efficiency for the specialties fuel series averaged 87.5%, somewhat lower than the coal average of 91.7 percent. Unit performance under engineered fuel was comparable to coal. Coal turbine efficiency was 36.27% virtually unchanged under engineered fuel. Fig 1d shows Unit 3 engineered fuel performance.

Fig 1d- Unit 3 Engr Fuel Peformance
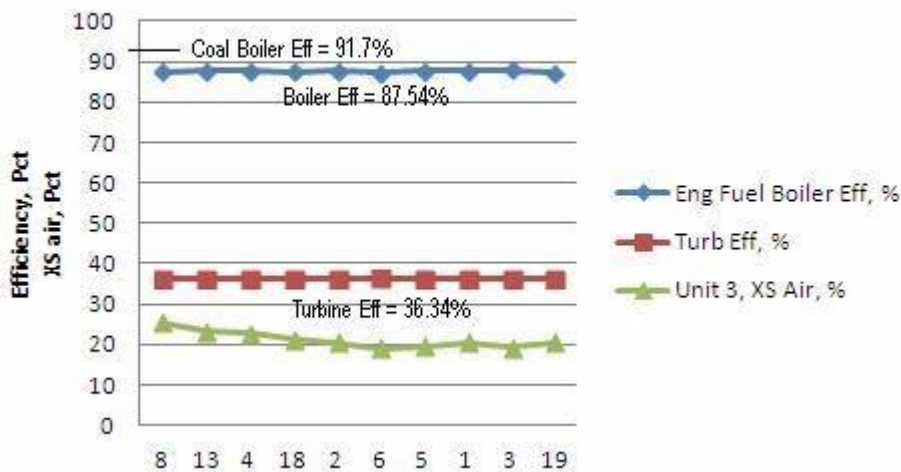
NOx

The principal pollutants quantified were NO and N_2O lumped together as NOx. N_2O was included per IPCC recommendations on MSW combustors from six classifications per metric ton. This study averaged the midpoints of each range and converted the units to Metric Ton of Carbon Equivalents (MTCE) of N_2O per ton of MSW. The estimate is 0.01 mass fraction N_2O per MTCE of waste fuel. Other oxides of nitrogen such as N_2O_5 were not considered.

There is no agreement among researchers on the effects of nitrogen content in coal or its conversion into NOx. In general, the increase in nitrogen content in coal results in enhanced NOx emissions However, coals with the same nitrogen content and the same degree of coalification may significantly differ with respect to nitrogen oxide emissions.[14]

Lower primary air temperatures minimize NOx emissions. Furnace bank (99%) and Economizer adsorption need to remain high (98%) to keep NOX emissions down as lower absorption can elevate NOx emissions 3 to 7 times. As expected, raising excess oxygen levels increased NOx, in one case by 8.5% and also elevated SO2 by 0.35 percent.
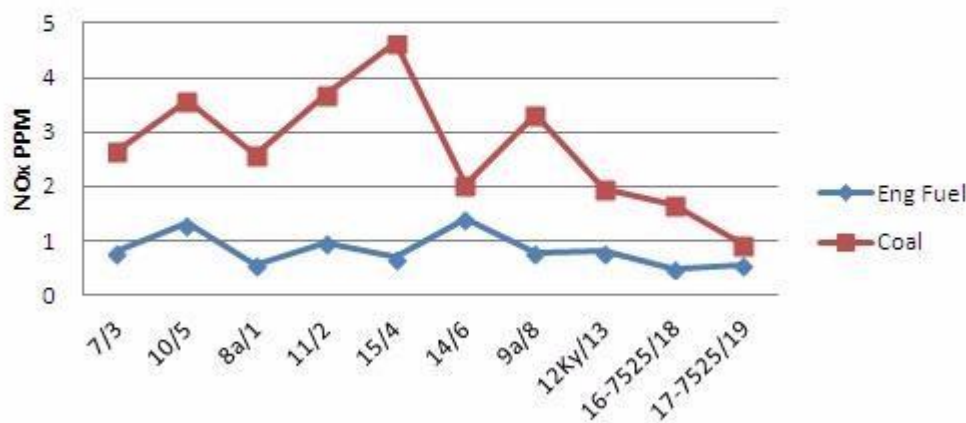
Fig 2 - NOx Emissions Coal vs Eng Fuel

Figure two compares NOx generated by the coal series versus engineered fuels. Specialty engineered fuels are depicted by the blue curve. The 2017 NOX level for Unit 3 was not noted on figure 2 as primary air temperature was reduced from the normal 547 ºF operation and excess oxygen was controlled at the lowest practicable level in all test trials.

NOx generation was noticeably lower in all cases. Test 17-7525/19 is a blend of coal and MSW without shredded tires that produced NOx levels close to engineered fuel No. 19. Although only twenty tests were performed the specialty fuels clearly outperformed the coal series in lower nitric oxide levels.

Sulfur

A ninety percent sulfur recovery level was assumed for both conventional coal and the specialty fuels. Figure three reports the unrecoverable sulfur released as emissions to the atmosphere and shows the comparison between the specialty and coal fuel series. Coal cases 7, 10, 11, 15,14 and 9a had equivalent or lower sulfur emissions than engineered fuel samples 3, 5, 2, 4 , 6 and 8. Engineered fuel samples 19, 13, 18 and 1 had lower sulfur emissions than coal samples 17-7525, 12-KY, 16-7525, and 8c but were not lower than the first coal series.

All MSW sulfur emissions fell below the 2016 Unit 3 162 ppm upgrade level.

Fig 3 - SO2 Emissions Coal vs Eng Fuel
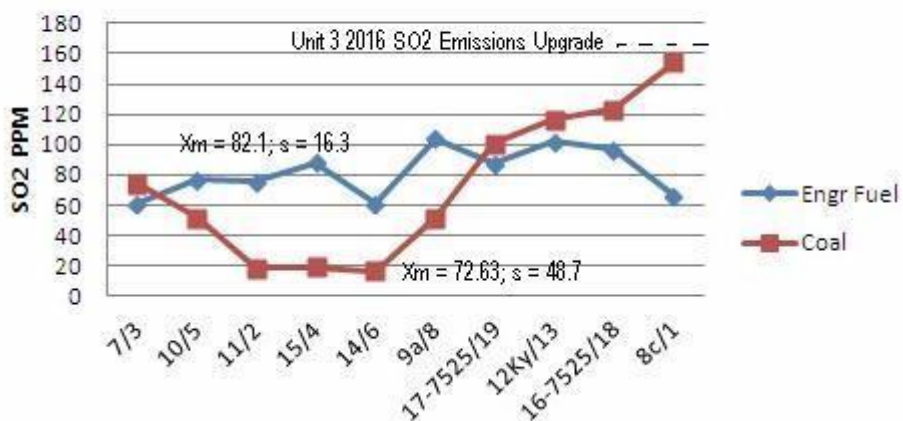
Mercury emissions for the coal series was not quantified because these emissions were essentially zero combusting engineered fuel.

Economics

Coal pricing was fixed at $55.00 per long ton in the simulation. Generating costs were calculated in dollars per million Btu.

$\textbf{\$Fuel} = \$/\text{Long ton} \times 10^6) / (2240 \times HHV)$

Waste fuel costs were calculated per ton based on a variety of factors such as transportation, the expenses of separating and blending the materials. Most tire derived fuels sell for somewhere between $20 - $60 per ton while tire derived aggregate is usually around $10 - $20 per ton.

Engineered fuel costs assumed the higher range from a low of $42 to a high of $61 per long ton. Pre-treatment of fuels to remove sulfur, tipping fees, amortization and taxes were not considered in the cost assessment.

The median cost for engineered fuel was $1.83 per 10^6 Btu as shown in Figure 4 while coal priced at $1.92 for 10^6 Btu representing a theoretical 4.6 percent reduction in fuel costs.

Test 16-7525 is a fuel sample mix of 75% by weight of Case 13 engineered fuel and 25% by weight of a 67% carbon bituminous coal (Case 7) providing a cost of $1.41 per 10^6 Btu which is the lowest cost of the entire series.

Test 17-7525 blended 75% by weight of Case 7 coal containing 3,7% Sulfur with 25% EPA 2005 solid waste reducing sulfur content to 2.8% The resulting emissions although higher than Case 7 coal were 1.4% lower than Case 13 engineered fuel with the same 2.8% sulfur content.

Fig 4 - Unit 3 Operating Cost Comparison Engr Fuel vs Coal
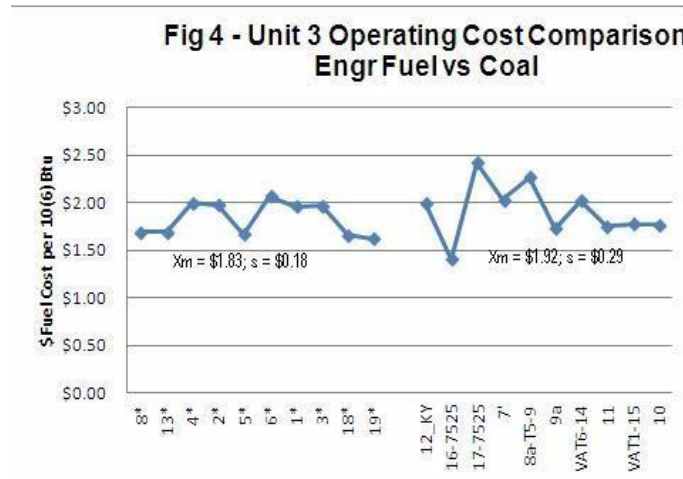
Model revenue computations were based on a revenue return of $0.073 per Kilowatt hour.

Conclusions

Equivalent power generation at full load was observed for all the engineered fuel cases despite increased fuel consumption. Most blended fuels can be utilized within the existing Unit 3 coal handling capability.

In some MSW tests the plant's pulverizers would have to operate at full capacity to handle higher fuel loads because of reduced carbon content. This would require either selection of more favorable engineered fuel compositions such as 17-7525 or specialty modifications to the plant's fuel handling system.

There were no detrimental effects from reduced bank effectiveness using engineered fuel. A highly desirable condition to rid municipalities of accumulated wastes which otherwise would be interred in landfill.

Engineered fuels reduce NOX emissions below that of coal and some blends provide lower sulfur emissions than coal. Judicious selection of engineered fuel blending compositions can make SO2 emissions competitive with coal.

Modeling fuel applications helps the plant comply with environmental requirements and reduces operating cost by providing custom fuels for optimum performance and minimum cost.

Additional Savings are realized because of essentially zero mercury releases with engineered fuels.

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