

EVALUATION OF RDF WASTE MANAGEMENT ALTERNATIVES FOR TWO SOUTH CAROLINA COUNTIES

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SUMMARY

Berkeley and Dorchester counties, South Carolina were seeking a strategy to extend landfill life in an environmentally sound and economic way. Santee Cooper, the local electric utility, was interested in obtaining low cost fuels as an alternative to coal. These objectives led the two groups to join in a collaborative investigation of technology to co-fire RDF with coal. The project was initiated based on a simple concept: the addition of pelletized RDF to the belts feeding the coal crushers at Santee Cooper's Jefferies plant. Technical failure of this alternative led to exploration of more conventional firing of fluff RDF and coal in their newer #3 and #4 boilers and to re-working of the older #1 and #2 boilers to a fluidized bed configuration. Intensive technical, economic and regulatory analysis showed that the fluid bed concept was technically plausible, economically reasonable and environmentally sound. However, as the project had evolved, the institutional complexity, liabilities and techno/economic risks had ballooned. The result was a project that the parties could not readily adopt. This paper summarizes the path followed in exploring the technical and institutional issues and the economic complexities of this project as a case example that may be useful to others in the field.

INTRODUCTION AND BACKGROUND

Berkeley and Dorchester counties, South Carolina, recently evaluated the use of facilities at Santee Cooper's Jefferies Electric Generation Station potential component of an integrated solid waste management system. Berkeley

County was in the process of implementing a landfill expansion that would extend the life of their present landfill by 20 years. However, they foresaw significant difficulties and greatly increased costs in siting subsequent facilities. The proposed co-combustion concept would extend the life of the new landfill to almost 50 years.

Preliminary economic analysis indicated that mass burn or dedicated RDF-only boiler approaches would not be feasible for the counties without importing a very large quantity of waste: two to three times the waste generated by Berkeley County alone. Further, the capital investment would be very high. While such approaches were considered to be politically viable, the County did not wish to assume the lead role nor to capitalize such a venture at this time. However, the co-burning alternative had the potential to make use of a substantial existing investment in capital facilities (the combustion, air pollution control and energy conversion equipment) and economy of scale in operating and maintenance staff. Also, it seemed likely that co-combustion could become economically feasible at a burning rate much closer to the current Berkeley (plus Dorchester) County waste generation rate. For these reasons, the project settled on co-burning as an attractive and appropriate strategy.

The proposed combustion-based plan involved the design, construction and operation of a plant to process refuse into a refuse derived fuel (RDF). This fuel would then be burned in one or more of the power boilers at the Jefferies Station of Santee Cooper, the regional power utility. Santee Cooper is 100% owned by the State of South Carolina. As such, the utility has a special interest and concern to join in the solution of community and county

problems, provided that they are consistent with its charter of providing electrical services at the lowest net cost.

The Jefferies Generating Station includes four boilers. Boilers 1 and 2 were installed in 1954. Both boilers were originally 46 MWe front-fired, pulverized coal (PC) fired systems furnished by Riley Stoker Corporation. They were converted to No. 6 residual oil firing in 1980 at which time their electrostatic precipitators were removed. Boilers 3 and 4 are each 165 MWe pulverized coal, front-fired Riley systems operating at a design pressure of 2475 psia at 1005 F total temperature with 1005 F reheat. They are equipped with electrostatic precipitators. The larger boilers were installed in the early 1970's. At present, Boilers 1 and 2 are used only for peaking; they are shut down entirely during most of the year and are brought on-line only to meet peak demands. Boilers 3 and 4 presently operate at about a 75% capacity factor. New and more efficient generating capacity just coming on-line at Santee Cooper's new Cross Generating Station, however, will rapidly shift the character of the total generation at Jefferies from base load to peaking service.

Initially, Santee Cooper believed that the use of RDF pellets would present the simplest approach for storage and handling of RDF at Jefferies under the existing facility constraints. By introducing the pellets onto the coal conveyor and allowing them to proceed along with the coal through the crushers and pulverizers, it was theorized that the material could then burn in suspension in the suspension boilers. Working in cooperation with the engineering and management staff of Santee Cooper, the counties secured a quantity (approximately 17 tons) of densified RDF (d-RDF) from a Tennessee-based processing operation for use in a "trial burn" at the Jefferies Station. The test was held on April 21, 1993. The test was to evaluate the existing materials processing and conveying facilities in handling and burning RDF and, to a limited extent, to evaluate the response of the combustion facilities.

The test revealed serious problems with the coal crushers and pulverizers. The RDF material had "fluffed" in the course of transportation and handling. Thus, a large fraction of the RDF handled resembled the 1 $\frac{3}{4}$ inches refuse top size material generated prior to densification. The RDF accumulated and packed into the gaps between crusher hammers. Considerable RDF (esp. the sheet plastic material) accumulated in the pulverizers such that the processing rate had to be greatly restricted (to as low as 28% of normal). It appeared that the RDF was plugging the grids in the pulverizer and reducing air flow. As a consequence, the boiler had to be severely derated. Also, there were significant "housekeeping" problems all along the coal/RDF path due to blow-off of waste, air suspension and carry-over at transfer points..

The combustion characteristics of the boiler did not experience any noticeable adverse effects from co-burning

RDF and coal. Although the quantities burned were limited, no problems with combustion instability or smoking were noted. Bottom and fly ash samples showed no change in carbon content or fusion when co-firing.

Despite the problems encountered during the Jefferies Station trials, the interest and commitment of both the utility and the two counties to the RDF concept remained strong. It was concluded that a major problem area was the large size of the basic RDF comprising the densified pellets. A second "trial burn" to test this hypothesis was held in early July 1993 using pellets formed from one-inch top size material. The resulting performance improved over the earlier test results. However, significant derating of the boilers was still required due to blockage of the pulverizers. The team concluded that this technical approach should be abandoned.

The disappointing outcome of the test program led to several meetings and technical discussions between the counties, Santee Cooper and their engineering consultant, Camp Dresser & McKee Inc. (CDM). They reached consensus on the following:

- The Trial Burn showed that the existing pulverizer was not suitable for handling a combination of coal and RDF pellets. Separate RDF processing and injection systems would be necessary.
- Engineering evaluations of alternative feed and burning schemes for co-burning coal and RDF should be conducted. The objective would be to identify the most economical option that offered minimum technical risk and full environmental compliance.

Further, it was concluded that data, engineering analyses, economic evaluations and regulatory review were needed before the County Councils of Berkeley and Dorchester Counties and the Board of Directors of Santee Cooper could commit to a joint waste-to-energy system. From the counties point of view, they had to:

- Define a guaranteed waste supply. This included domestic wastes from Berkeley County and Dorchester counties and, potentially, waste from other nearby counties.
- Define a combustion concept (integrated with the existing or modified Jefferies Station facilities) that was technically plausible with a minimum of technological risk. This would, perhaps, allow modest modifications of existing Santee Cooper facilities to configurations proved by other utility operators to function at an acceptable level.
- Define the financial context of the project involving matters such as the means and responsibility for securing capital, the revenue basis (value of RDF as a fuel or of electricity), and the basis for a working relationship that was acceptable to both the counties and to Santee Cooper.

DISCUSSION

Waste Supply

Ensuring an adequate quantity and continuing supply of waste was seen as critical to developing an efficient long-term operation of an RDF dependent system. Further, a credible, quantitative basis was needed to establish the processing rate underlying the technical and economic evaluations in the project. Several potential sources for a reliable supply of waste or other fuels with a uniform consistency included municipal solid waste from Berkeley and Dorchester counties, municipal solid waste from neighboring counties, wood waste, and coal. A waste characterization study was conducted in the spring of 1993 to determine the composition of the municipal waste stream. Table 1 presents a summary of the results.

Wood waste was also evaluated as a potential fuel. Experience in several facilities had shown that co-burning of coal and wood was feasible and it was known that several industrial and small cogeneration facilities in the region used wood wastes as fuels on a regular basis. Contacts with wood waste brokers, wood waste generators and wood waste users showed that this fuel would be available from time to time at an attractive price in comparison to purchased fossil fuel. However, the supply of the material and the reliability of supply would be uncertain. Contracting for wood as a fuel was economically unattractive vis a vis the present and projected coal price structure. The final conclusion was to consider making provision to receive and handle wood waste but not to consider this fuel as a firm part of any final co-burning system.

Technical Evaluation of Co-burning Options and RDF Preparation

Refuse-coal co-burning under a "suspension burning" scenario has been accomplished in the United States by several utilities and large industrial boilers on a long-term (up to 17 years) basis. Front-fired (FF), cyclone-fired (CF) and tangentially fired (TF) boiler designs have been employed. Also, fluid bed (FB) co-burning in a bubbling bed mode has performed well in both utility and industrial service. Facilities currently co-burning RDF and coal involved include:

- Union Electric-TF-(St. Louis, MO)
- Ames Municipal Light Co.-FF, TF-(Ames, IA)
- Lakeland Municipal Light Co.-FF-(Lakeland, FL)
- Madison Gas and Electric-TF-(Madison, WI)
- Rochester Gas and Electric-TF-(Rochester, NY)
- Potomac Electric Plant-TF-(Dickerson Station, MD)
- Northern States Power-CF, TF-(Several)
- Eastman Kodak Co.-TF-(Rochester, NY)

**TABLE 1 WASTE COMPOSITION
IN TONS PER DAY (1993)**

Source:	Dorchester Co.				Berkeley Co.			
	MSW	TPD	MSW	TPD	Ind.	TPD	C&D	TPD
Base Quantity		140.0		216.0		65.0		25.0
Component	%	TPD	%	TPD				
Paper	41.10	57.50	40.70	87.91	35.00	22.75		
Plastics	11.00	15.50	12.80	27.65	40.00	26.00	0.60	0.15
Textiles	5.50	7.70	7.00	15.12				
Rubber/Leather	0.10	0.14	1.10	2.38				
Food Waste	15.60	21.80	8.70	18.79				
Wood Waste	6.40	8.96	3.60	7.78			7.90	1.98
Yard Waste	4.30	6.02	5.70	12.31				
Other Organic	0.90	1.26	3.30	7.13			1.86	465
Aluminum	1.20	1.68	1.30	2.81				
Other Metals	5.10	7.14	4.70	10.15	25.00	16.25	3.30	.825
Other Inorganic	3.90	5.46	4.30	9.29			86.00	21.5
Glass	4.90	6.86	6.80	14.69			0.32	0.08
Total	100.0	140.0	100.0	216.0	100.0	65.0	99.98	25.0

Source: Waste Characterization Study, 1993

Ind. = Industrial Wastes

C&D = Construction & Demolition Waste

MSW = Municipal Solid Waste from Dorchester County and Residential, Governmental, and Commercial Waste from Berkeley County

- Tacoma Municipal Electric-FB-(Tacoma, WA)
- Northern States Power-FB-(Lacrosse, WI)
- Industrial sites (e.g., DuPont)-FB-(Several)

A review of the design characteristics of the Jefferies Station boilers indicated that boilers #1 and #2 could be converted to the fluid bed concept and boilers #3 and #4 could be converted to front-fired, suspension burning of RDF.

Suspension Burning (Front-Fired). The interest of the counties focussed on experience with the front-fired units such as those at the Jefferies Station. In front-fired units equipped with burn-out grates, a maximum particle size between 1-inch and 1.5-inch (2.5 and 3.8 cm) appeared to be optimal. Tests by Potomac Electric Company with RDF shredded to 95% minus $\frac{3}{8}$ -inch (one centimeter) reached the point where the unburned carbon content in the flyash indicated that burnout grate was no longer necessary. However, the high cost of processing the refuse made this strategy unattractive.

Achieving complete burnout of co-fired RDF with acceptable processing costs required the installation of a burnout grate at the bottom of the primary furnace. The grate not only helps to achieve substantial burnout (realization of most of the heating value of the waste material) but it eliminates the problem of fires from the ac-

cumulation of combustible waste material in the ash handling system. The burnout grates used successfully to date are simple, flat, dump-type grates. Several operators have modified the size and shape of the air holes (increasing the hole area and changing them from circular to slots). For Jefferies, both the grates and the over and underfire air supply system would have to be added for co-burning in boilers #3 or #4.

Most U.S. utilities have operated suspension fired boilers on mixtures of RDF and coal rather than RDF only. The RDF has been limited to a maximum of about 15 percent of the total furnace heat release rate. In view of the relative heating value and ash content of coal and RDF, this corresponds to about 30 percent of the total mass input and ash output. This also reflects the limits permitted by the federal EPA concerning the percent of RDF that can be burned before the air pollution emission requirements shift from those of a coal burning utility boiler to those of municipal waste incineration systems. Since the latter incur the need for acid gas control, monitoring for dioxin compounds and other pollutants, the 30% mass rate level remains as the maximum average firing rate where there is significant experience. The 15% heat input limit was selected by the counties and Santee Cooper as the appropriate processing level.

Fluid Bed Burning. A fluid bed incinerator for RDF involves a cylindrical or rectangular chamber containing coarse sand or similar bed material through which a gas is passed such as to cause the sand to bubble and boil much as a liquid. Contact between gas and solids is intimate and the large mass of the sand compared with the gas stabilizes the bed temperature. The fluid bed concept was originally developed as a solids-to-gas contacting device for catalytic operations in the petroleum field. The applicability of the principles of fluidization were soon extended to drying, ore processing and to waste incineration.

The development of technology to add boiler waterwall surface area to remove heat from the bed walls and bayonet tubes to remove heat from within the bed itself provided the key to the use of the fluid bed as a general-purpose combustor for solid fuels such as coal, refuse, and wood. Because of the close parallels between the size, age, boiler type and many other aspects of the Northern States Power facility in LaCrosse, WI and the Tacoma Public Utilities operation in Tacoma, WA relative to the proposed Jefferies operation, current data on these two plants was reviewed. An inspection visit and operations analysis was conducted of the Energy Products of Idaho fluid bed system in Tacoma.

Regulatory Review

Key regulatory constraints that may be placed on any alternatives studied were evaluated. This included state and federal air pollution requirements and limitations in com-

bustion system capacity imposed by South Carolina law. The ramifications of the several proposed projects on "recycling credits" by the state of South Carolina were evaluated. Neither the county, the CDM team nor the Santee Cooper environmental group found any unresolvable regulatory problems or impediments except for a state law setting a 600 tons per day (TPD) limit on the capacity of "municipal refuse incinerators". This limit was seen as (possibly) constraining the achievement of optimum economical operation. More detailed discussions, however, lead to the conclusion that the combustion concept involved here would not fall within the definition of a "municipal refuse incinerator".

Economic Analysis

Scenarios Considered. The economic analysis was developed by analyzing four waste generation cases that included a total of ten disposal scenarios, each over a 20-year project life beginning in the year 1997. The ten scenarios involved four "Cases" (differing tons per day *processing rates* in the initial year) and three "Alternatives" (differing *technology*: landfill only, front-fired suspension burning with coal and fluid bed burning). The quantity of refuse was varied year-by-year based upon waste generation projections.

Alternative 1 is the base case. For this situation, all of the waste generated in Berkeley County would be landfilled. Thus, a maximum of new landfill space would be required and the space would be consumed at a rate limited only as far as recycling is performed.

Alternative 2 is an embodiment of the successful suspension firing concept for RDF-coal co-combustion as seen in Ames, Lakeland, and Madison. The refuse would be shredded to a 1-inch topsize in an RDF preparation facility sited at the landfill. Following some combustor modifications, the RDF would be burned in suspension with coal in Boiler #3 or #4 at the Jefferies Station. No changes in either the air pollution control system or the ash handling systems were included in the plan and economic analysis considered. A conceptual process flow diagram for producing 1-inch top size material is included in Figure 1.

The RDF specifications that were identified as appropriate for the facility are as follows:

Ultimate Analysis:

H ₂ O	26.80%
N ₂	0.65%
H ₂	4.36%
O ₂	26.68%
S	0.10%
C	32.01%
Cl ₂	0.40%
Ash	9.00%
Heating Value:	6,000 Btu/lb (3,335 kcal/kg)

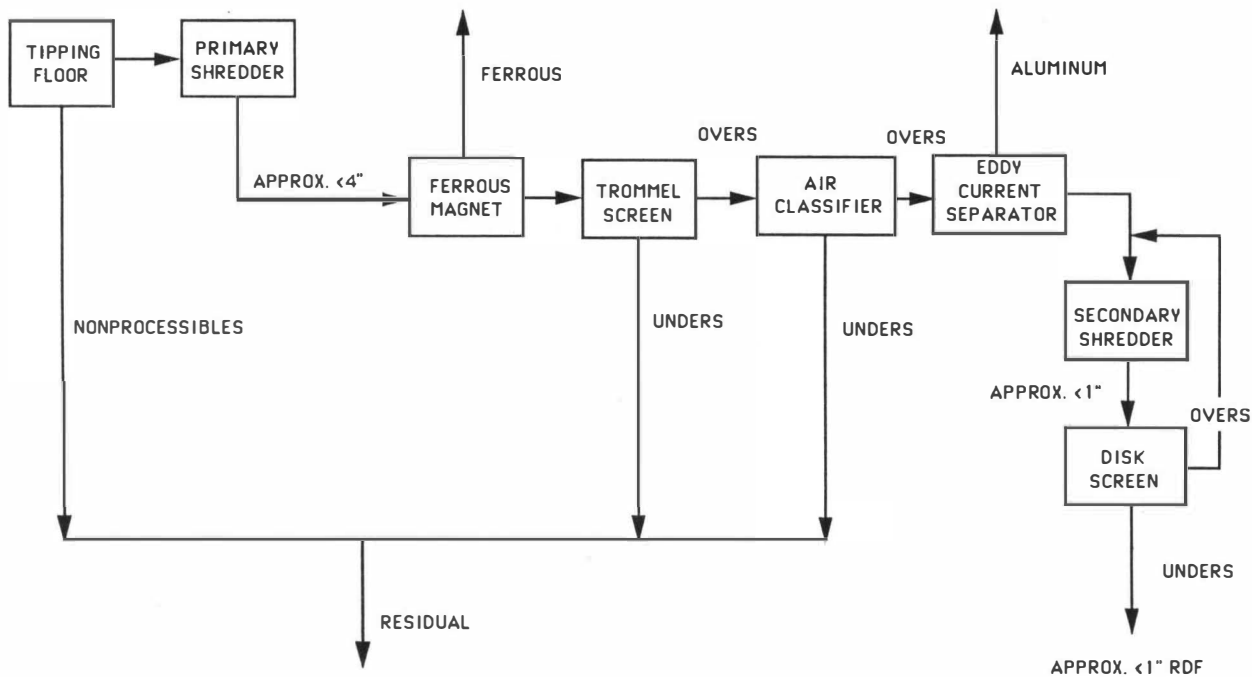


FIG. 1 MIXED WASTE PROCESSING FACILITY CONCEPTUAL PROCESS FLOW DIAGRAM (To Produce RDF Less Than or Equal to 1" Particle Size)

Ferrous Material Removal: Greater than 95%
 Glass Removal: Greater than 90%
 Grit Removal: Greater than 90%
 Maximum Fuel Size: One (1) inch (2.5 cm)

Alternative 3 is an embodiment of the successful fluid bed firing concept for RDF, coal and/or wood co-combustion used in LaCrosse, WI and Tacoma, WA. The refuse would be shredded to a 6-inch topsize in an RDF preparation facility sited at the landfill. The RDF would be burned at the Jefferies Station in either Boiler #1 or #2 following major rework of the boilers to a fluid bed boiler configuration. Also, a spray dryer, fabric filter air pollution control system would be added. The existing power island would be retained intact.

The ten scenarios are:

- Case 1: Berkeley County "Go-it-alone"
 - Alternative 1: Landfill all waste
 - Alternative 2: 1-inch RDF in Boiler No. 4 (Suspension Burning)
 - Alternative 3: 6-inch RDF in Fluid Bed Boiler No.1
- Case 2: Berkeley plus Dorchester County
 - Alternative 1: Landfill all waste

- Alternative 2: 1-inch RDF in Boiler No. 4 (Suspension Burning)
- Alternative 3: 6-inch RDF in Fluid Bed Boiler No.1
- Case 3: Berkeley/Dorchester Co. plus import waste (500 TPD in 1997)
 - Alternative 2: 1-inch RDF in Boiler No. 4 (Suspension Burning)
 - Alternative 3: 6-inch RDF in Fluid Bed Boiler No.1
- Case 4: Berkeley/Dorchester Co. plus import waste (800 TPD in 1997)
 - Alternative 2: 1-inch RDF in Boiler No. 4 (Suspension Burning)
 - Alternative 3: 6-inch RDF in Fluid Bed Boiler No.1

Preliminary Economic Analysis

In the comparative economic analysis, capital investments were estimated and disbursement schedules developed over a 20-year venture life. An assumed annual inflation rate of 4% was used. For each year after the outlay, an annual assessment was made covering retirement of capital and interest payments such that all borrowing was repaid at the end of the 20-year overall venture life.

TABLE 2 DISCOUNTED 20-YEAR PROJECT TIPPING FEE (BASIS: PRELIMINARY ANALYSIS)

<u>Scenario</u>	<u>Discounted Tipping Fee (\$/Ton)</u>
Case 1, Alt. 1 (Berkeley only, landfill)	\$24.87
Case 1, Alt. 2 (Berkeley only, suspension burn)	\$46.51
Case 1, Alt. 3 (Berkeley only, fluid bed)	\$45.18
Case 2, Alt. 1 (Berkeley+ Dorchester, landfill)	\$20.33
Case 2, Alt. 2 (Berkeley+ Dorchester, susp. burn)	\$43.00
Case 2, Alt. 3 (Berkeley+ Dorchester, fluid bed)	\$32.59
Case 3, Alt. 2 (500 TPD in 1997, suspension burn)	\$38.67
Case 3, Alt. 3 (500 TPD in 1997, fluid bed)	\$24.86
Case 4, Alt. 2 (800 TPD in 1997, suspension burn)	\$26.53
Case 4, Alt. 3 (800 TPD in 1997, fluid bed)	\$15.99

Operating expenses were estimated year-by-year based on the actual processing rates, electrical generation etc.

Landfill expense was analyzed both as a “competitor” for the county waste disposal concept (Alternative 1) and as a support activity handling ash and RDF reject material for all other scenarios. The basic economic relationships of a new landfill in Berkeley county were developed using a spreadsheet-based model. The model estimated the needed landfill area based on the total emplacement (cubic yards) over the 20-year operating period. The landfill size and cost, thus varied for each process scenario (suspension vs fluid bed firing, RDF reject ratio etc.). Landfill capitalization was estimated assuming four (4) phases of landfill development and a 30-year post-closure groundwater monitoring expense. The landfill cost data were interpolated and extrapolated to yield phase-by-phase capital cost and disbursement schedules, costs for cover material and other operating expense and the accumulation of financial reserves for post-closure long-term monitoring expenses.

It was assumed that Berkeley county would be the site of the RDF reject and ash landfill for all scenarios. It was assumed that the county could borrow money at 7% interest to capitalize the landfill development and the final closure and all RDF processing and boiler-related investments. A constant inflation rate of 4% was presumed over the 20-year analysis period. The results of these analyses and calculations was an annual cost (debt service and inflated operating cost) for each of the 20 years of landfill operation and the 30-year monitoring period thereafter.

Capital and operating costs were developed for the RDF processing facilities and for the boiler modifications and air pollution control upgrades. For lesser average tonnages, a single, 50 ton per hour RDF line is adequate to process the waste over the entire project life. For situations where out-of-county waste is imported to improve economies of scale, a second RDF line of similar capacity becomes necessary at some point in the project life.

Based on vendor quotations for the processing lines and CDM cost data for buildings and infrastructure, the capital investment for four RDF processing facilities were developed. The four facilities comprise systems with one or two processing lines generating 1-inch or 6-inch top size RDF. From the waste feed rates, the net RDF production rates and associated fixed and variable components of the operating cost were estimated.

It was determined that for the fluid bed base case, the conversion would require derating Boiler #1 (or #2) to 20 MWe from their design rating of 46 MWe and setting a floor of 15 MWe generation. Derating was required due to a limitation in the bed heat release rate (Btu/hr/ft²) that corresponds to the existing boiler footprint. No derating is necessary for the suspension firing in Boiler #3 or #4. The minimum steaming rate for Boiler #3 or #4 was set at 60 MWe. The minimum steaming rates were due, importantly, to operating limitations associated with burner and pulverizer turndown limits and did not relate to RDF burning.

Over the 20-year period, the daily refuse quantity increases and, thus, the daily combustion rate increases. When this increase required a boiler on-line factor greater than 85%, it was assumed that a second phase of boiler conversion would be undertaken. For the fluid bed option, an expansion approach is available that is more cost-effective than conversion of the second boiler. This would involve adding an external fluid bed combustion unit off to the side of the initial boiler that releases its exhaust gases into the boiler. This permits the boiler to be re-rated at 40 MWe while retaining the minimum 15 MWe steaming rate. However, the better option is to convert the second furnace. Thereby, a greater degree of disposal reliability is achieved with only a small increase in cost.

The quantity of coal that must be burned in each boiler type was estimated on a year-by-year basis. This base-line coal utilization may be due to the technical characteristics of the co-burning technology. Specifically, in the front fired burning case, the maximum refuse heat release was 15% of the total (to avoid air pollution control retrofit). Since the fluid bed system required a new air pollution control system anyway, a dry scrubber/baghouse was installed. This, combined with the inherent flexibility of the fluid bed combustion system made it possible to run (if desired) with no coal firing. For both burning schemes, however, coal burning may be necessary to achieve the required minimum steaming rate for satisfactory turbine operation.

From these calculated projections of annual RDF burning and coal co-burning and the basic design generation capacity of the affected boiler(s), the minimum capacity factor was calculated (the percent of rated generation capacity corresponding to the actual production rate of electricity) for each year to consume all of the RDF. For this assessment, we assumed that the county would be paid

the fuel value of the RDF at the price of coal (\$/million Btu). However, economic optimization of the Santee Cooper system will require an additional fuel-related cash flow under certain circumstances.

As the electrical demand fluctuates during a given day, all utility companies use a computer-based dispatch program to decide (on a minute-to-minute basis) which of their several boilers should be used and which should be “backed off”. The decision is based on the basic thermal efficiency of each boiler (the “Heat Rate” expressed in Btu per kilowatt hour), the cost of the particular fuel used in the boiler, the anticipated sulfur dioxide emissions in comparison with permit limitations and other factors. This continuous evaluation process produces an operating pattern with the lowest net generating cost across the system. If a utility has a new and relatively efficient boiler (such as the Jefferies #3 and 4 are at the present), the projected capacity factor of that boiler will be high. Older, less efficient boilers, however, become less and less utilized as the new units come on-line.

As long as the capacity factor (percent of design capacity) for the converted RDF-coal boilers that corresponds to disposal of all of the RDF is equal to or greater than the boiler utilization projected for that unit by Santee Cooper, the economic analysis, will require no modification. If, however, the projected co-disposal boiler utilization is lower than needed for the RDF (i.e., there are more efficient, more economical boilers available to meet the demand), it is necessary for the county to provide an economic incentive to Santee Cooper such that the computer-based dispatch program will “change its mind” and redirect the responsibility for generation to the desired co-burning unit.

The specific amount of this “fuel cost subsidy” payment, year by year for each of the cases was estimated in cooperation with the Santee Cooper staff. They accomplished this task by using different fuel costs for the converted boilers each year, thus modifying the projected use profile of the several boilers in the Santee Cooper system. This was done for the eight combustion scenarios: four cases, each with two alternatives for each hour of the 20 years of operation.

The analysis identified eight combustion scenarios. Case 1 was quite static with no change in the combustion systems over the 20 year project period. Case 4 was considerably more dynamic with implementation of several upgrades (to increase processing capacity) in the course of the project period.

The cost for each year (landfill, RDF facility, boiler operation and all fuel payments and subsidies) was then discounted at a 7% rate and the discounted annual cost was summed over the 50 year time period (20 year combustion project life followed by 30 years of post-closure landfill monitoring) to yield a total discounted present worth for the two landfill-only scenarios and for the eight land-

fill plus boiler RDF/coal co-burning alternatives. Also, the net cost per ton was calculated for a constant, 1993 dollar value and a net cost on a “dollars per household per month” basis was calculated with constant-value dollars.

The total cost of disposal was calculated on a year-by-year basis with inflation effects accounted for at a flat, 4% annual rate. For the landfill-only scenario, the cost is comprised of the following:

- *Annual capital charges* that are calculated using the Capital Recovery Factor (CRF) with 7% interest for the term of the pertinent years of the overall 20-year project life for the initial facility development plus for the development investment for each subsequent phase. In addition, there is an annual capital charge assessment associated with the accumulation of a fund covering the closure costs.

- *Annual operating charges* (calculated as an assessment for cover material at \$2.00 per ton of material land-filled) plus a fixed annual operating cost that is scaled with the general size of the fill.

- *Annual monitoring costs* for the 30-year post closure period at an annual rate scaled with the general size of the landfill.

- *Contingency* at a fixed rate of \$750,000 per year (plus inflation) over the 20-year life.

For combustion alternatives, there is a landfill component (calculated as above) for the residue from the RDF operation plus the following cost elements related to the combustion operation.

- *Annual capital charges* calculated using a CRF with a 7% interest rate for the initial and any new RDF and boiler capital investment.

- *Annual operating charges for making RDF* (calculated using the specific waste feed rate as a parameter in a \$/ton formula that generates the variable and semi-variable cost elements of the RDF facility).

- *Annual operating charges for hauling RDF* from the landfill to Jefferies.

- *Annual credit for the heat content* (millions of Btu) in the RDF.

- *Contingency* at a fixed rate of \$1,500,000 per year (plus inflation) over the 20-year life.

- *Annual fuel subsidy* (a charge to the project) paid to Santee Cooper and calculated as follows:

- Calculate the annual RDF heat release (MMBtu/year)

- Based on the requirements of the combustion technology, calculate the quantity of coal (expressed in millions of Btu/year) that must be burned with the RDF. This heat release ratio is 5.67 : 1 (coal : /*rmRDF*) for suspension burning and zero (no coal is required) for the fluid bed.

- From the coal plus RDF heat release, calculate the average megawatt generation from the boiler. For the fluid bed case, use data provided by Santee Cooper to vary the heat rate with the generating load. The heat rate varies from a high of 15,000 Btu/kWh at 15 MWe to about 13,500

Btu/kwh at 40 MWe. Compare with the minimum capacity factor (the ratio between the actual and the design megawatt generation rate for a given boiler) that corresponds to acceptable turbine operation (60 MWe for boilers #3 or #4 and 15 MWe for boilers #1 or #2). If below the minimum, burn additional coal to reach the minimum.

- At the minimum or the actual (whichever is higher) MWe level, use the Santee Cooper boiler dispatch computer program to assess the degree to which the boiler, at full fuel price, will be used. If this exceeds the needed operating level, the subsidy is zero. If not, the effective fuel price (RDF plus coal) must be reduced until a point is found where the pertinent boiler operates at the needed capacity factor. It is assumed that the load was switched from the newer Cross Station (9,750 Btu/kWh). The fuel subsidy was then calculated from the difference in heat rates and added as a cost to the waste combustion operating cost.

The annual costs were then summed on a yearly basis to yield the annual cost (in inflated dollars) for operation of each of the various scenarios. These annual cost figures were then discounted at 7%, totaled and divided by the total, 20-year waste throughput. This produced a value for the net, discounted project tipping fee over the 20-year operating life and including the 30-year post-closure landfill monitoring period.

The economic analysis showed clearly that the Berkeley County-only cases were economically unacceptable. The small quantity of refuse available is insufficient to support the large capital investments and operating expenses of RDF and combustion facilities. When Dorchester County waste is included, the costs for combustion-based disposal are still high relative to landfilling the waste. However, the cost premium involved is approaching the range where other jurisdictions (e.g., Hillsborough county FL and both Kent and Oakland county MI) have selected a waste-to-energy concept as an environmentally sound means to achieve energy recovery objectives, offset fossil fuel combustion and reduce landfill size and/or extend landfill life.

When still more waste was imported (from 150 to 450 tons per day of waste from other jurisdictions), the cost for combustion becomes less than landfill for the fluid bed alternative. In all cases, the costs for the fluid bed alternative is significantly less than for the front-fired suspension burning. Also, the technical features of the fluid bed make it amenable to the opportunistic use of wood waste when available at attractive prices. Based on these conclusions from the preliminary analysis, the fluid bed alternative at a 500 TPD in 1997 level was subjected to more intensive analysis.

Detailed Economic Analysis. Much of the framework of the preliminary analysis was retained. However, discussions with Santee Cooper suggested an alternative County-Utility relationship that involved county capital-

ization of the facility upgrades and conversion and utility management, operation and maintenance of the facilities (all costs to be invoiced on a full reimbursement basis). Electricity generated in the facilities would be purchased at a price to be negotiated. For purposes of this evaluation, the Santee Cooper system average coal-based cost of generation was used. Another consideration, the possible requirement for the purchase of "air emission increments" (for sulfur dioxide emissions), was suggested as a County responsibility. More likely, however, the RDF unit will emit considerably less than the Cross station emissions and air emission increment *credits* may be generated. This latter matter was left for resolution in subsequent evaluations and negotiations.

The capital investment estimates for the fluid bed alternative were refined by JWP (the fluid bed vendor) in association with Riley Stoker. The RDF facilities were re-evaluated to establish an economically optimum time for installation of the second processing line. An inspection of the Boiler #1 and #2 complex was accomplished to assess the needs for upgrading and refurbishment supporting an additional 20 years of operating life. Cost estimates were prepared for these changes. The landfill size and operating costs were modified to account for the return of RDF ash to the landfill (on the return segment of the RDF transport operation). The possibility of using the ash for daily cover at the landfill will be explored in future studies. If this can be done, considerable cost and landfill volume reductions can be realized.

The requirement for an additional capital expenditure for a cooling tower serving the Unit #1 and #2 boilers (approximately \$1,000,000 in 1993 dollars) was recognized as a possibility if Santee Cooper is unable to accomplish its water management responsibilities while meeting the cooling water demand of Units #1 and #2. The resolution of this need was left to the implementation phase of the project. It should be noted, however, that the annualized cost to the project of such a cooling tower would approximate \$125,000 whereas the project budget presently carries an annual \$350,000 "contingency" line item to provide for unforeseen requirements.

The operating and maintenance staffing requirements for the combustion facilities were developed through discussions with Santee Cooper. The staff levels were confirmed with JAP based on their experience in existing fluid bed plants. Also, the operating costs were adjusted to include boiler insurance (at rates provided by the present Santee Cooper carrier); the costs of utilities and water-treatment chemicals; and for the limestone and lime consumed for acid gas control as part of the air pollution control system. Finally, the revenue stream was recalculated to coincide with electrical generation. Annual revenues were calculated based on the anticipated annual electrical generation from RDF combustion and year-by-year projections of the expected value of a kilowatt hour (by Santee Cooper) for the 20-year project life. A contingency

TABLE 3 DISCOUNTED AVERAGE TIPPING FEE (BASIS: DETAILED ANALYSIS)

<u>Scenario</u>	<u>Discounted Average Tipping Fee (\$/Ton)</u>	<u>First Year Average Tipping Fee (\$/Ton)</u>
450 TPD (in 1997)	\$30.59	\$52.47
500 TPD (in 1997)	\$29.04	\$50.08
550 TPD (in 1997)	\$28.00	\$48.33
Berkeley Co. Landfill	\$24.87	\$45.70

allowance of \$350,000 per year (inflation adjusted) was retained through out the 20-year project.

The calculations were made for waste generation rates on both sides of a nominal 500 TPD (1997 rate): 450, 500 and 550 TPD. The resulting constant value tipping fees are shown in comparison to the landfill only scenario from the preliminary analysis. The discounted 20-year average and first year (1993 dollars) tipping fees are shown in Table 3.

CONCLUSIONS

These results showed the clear opportunity available to Berkeley and Dorchester counties and surrounding counties to implement a technology that offers several advantages:

- More than a two-fold increase in the operating lifetime of the planned 100-plus acre landfill expansion. The landfill life would approach 50 years.
- Addition of a third means of waste management (beyond landfill and recycling) to assure reliable solid waste management to the sponsoring counties far into the 21st century.
- Contribution to the achievement of the county's recycling goal by reuse of the fuel value of many refuse components having little or no materials reuse potential. Also, the RDF process line would include recovery of ferrous metal for recycling.
- A reduction in the burning of fossil fuel.
- Reuse of otherwise to-be-decommissioned generating capacity.

- Reduced or equal air emissions (on a mass per megawatt hour basis) relative to the fossil fuel combustor operation that the waste based generation would replace.

However, implementation of the project incurs the following disadvantages:

- A \$20/household per year cost increase.
- Although reuse of existing equipment significantly lowers the capital cost with some modest increase in O&M costs, it also introduces the risk that presently unknown major equipment problems exist, will become known after the project is implemented and the cost to fix these problems will have to be paid for by the project.
- The institutional relationship had become very complex. In the original concept, the County simply furnished a fuel material that (it was assumed) would be entirely compatible with existing fuel handling and firing equipment. This has changed to a highly inter-related service arrangement with long-term obligations to operate the Jefferies facility years beyond its expected economic life. This suggested significant liability and risk to Santee Cooper.
- The economic attractiveness of the combustion alternative is closely tied to waste throughput rates at or near 500 tons per day. Thus, feasibility of the project would depend on obtaining long-term waste commitments from neighboring counties or other waste sources.
- Potential risks are associated with extending the life of a 40-year-old station to provide an additional 20 years of service.

In view of these technical, environmental, institutional and economic conclusions, Berkeley County and Santee Cooper concluded that the benefits associated with the proposed project of converting Jefferies Unit No. 1 to a fluidized bed combustion facility were greatly diminished by the highly complex institutional relationships between one another and outlying county governments. Further, the project presented many uncertain technical and financial risks. Therefore, it was concluded that effort toward implementation of this embodiment of an energy recovery concept should be suspended. However, the basic fluid bed or front-fired suspension burning concepts and some other variations of co-firing RDF with coal may merit reconsideration from time-to-time as technological developments and experience reduce the uncertainties and risks.