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At the present time Florida Power & Light (FPL) has approximately 11,700 MWe of capacity, serving some 2.2 million customers in eastern and southern Florida. Of this 11,700 MWe, approximately 2,200 MWe are nuclear, and the remaining 9,500 MWe use oil and gas. Last year FPL burned some 40 million barrels of oil per year, most of it imported, which makes FPL the largest oil burning utility in the United States. An additional 14 million barrels of oil equivalent of gas is scheduled to be phased out by the end of this decade. If the present growth in the number of customers continues, FPL could be burning 60 million barrels of oil per year by 1990 unless it can change the situation.

About four years ago we began to look seriously at what might be done to convert some of our oil and gas burning equipment to coal, which is really the only alternative fossil fuel. First we began an extensive review of the coal gasification processes available. We even participated both financially and technically as a member of the evaluation team for one process, primarily to gain experience in the evaluation process and to determine some of the "real world" problems facing those involved in gasification technology. In many respects, none of the gasification processes really satisfied our needs because 24 of our 28 fossil plants are in congested areas where there is inadequate room for gasifiers in the immediate vicinity of the plant. This meant that the gasifier could not be closely coupled and integrated into the power plant, thereby providing the high efficiencies desired, and hence we would have to live with the lower efficiencies — typically 60 to 70% — associated with "over the fence" gasifiers located some distance from the power plant. Because of our location in Florida, far from the coal fields, the transportation costs were just too high for us to consider the possibility of utilizing coal inefficiently. Furthermore, the technology, as we saw it, was not ready for the rapid deployment which we felt might be thrust upon us very suddenly in the event of the cut-off of our oil supplies from overseas.

We also looked at liquefaction of coal as a possible means of providing a liquid fuel for our plant. The idea was that we could justify a premium price for liquid fuel that would use our existing liquid fuel handling facilities at our plants. We also looked at the possibility of converting coal into methanol because of its environmentally desirable burning characteristics, but the projected costs and uncertain technology mitigated against all these options, particularily in the short term.

It was apparent from the very beginning that there was much to be gained from cleaning the coal, especially when it was possible to do so before shipping it to Florida. The objective was primarily to remove as much of the ash and the sulfur as economically feasible. In addition to the various commercially used coal cleaning techniques, we investigated a number of proprietary processes including heavy media separation, dynamic mechanical processes, and chemical processes. Our basic rationale was that every pound of ash or sulfur that we could remove before the coal went into the furnace made it that much simpler to burn coal in furnaces that were not designed for coal, and also to make it that much easier to meet the environmental standards in a state that is widely known for its clean environment. Indeed, a fuel subsidiary of Florida Power & Light is presently supporting the development of proprietary coal cleaning technology with a view to making it available for our own use, as well as for others on a royalty basis.

The primary problem associated with burning coal in a power plant that was designed primarily for residual oil is the fact that coal burns differently than oil. As a result the amount of heat that is transferred from the burning fuel to the radiative and convective surfaces of the boiler differs. Pulverized coal usually ignites slower than atomized oil droplets and tends to burn longer. Since radiative heat transfer is approximately proportional to the fourth power of the temperature, the glowing, long-burning coal particles, which remain at a high temperature for a longer time, transfer more radiative heat than oil molecules which burn more rapidly. Hence the radiative heat section of a coal fired boiler must be larger for a given size plant than the corresponding section in an oil fired unit; which has a larger convective section and a smaller radiative section than a coal fired unit. Hence, there is a basic incompatibility in burning coal in a power plant designed to burn oil. There are, of course, means of compensating for this difference. One of them is to grind the coal finer so that it ignites and burns faster; another is to mix coal and oil together so that the fast igniting oil accelerates the burning of the coal. This is the essence of the theory of the coal-oil mixture. In practice, it doesn't always work out this way.

We, of course, were aware of the number of experiments with coal-oil mixtures carried out throughout the country. Specifically, Florida Power Corporation, our sister utility in St. Petersburg, had a very successful experiment using a super fine grind of coal mixed with oil. The flame was very stable and looked like an oil flame, and the ash which was predominantly due to the coal was not sticky. The stability of the fine coal and the oil was quite satisfactory with stirring, but the principal drawback was the cost of the fine grinding. We are also familiar with the Department of Energy sponsored experiment with New England Electric's Salem Harbor facility where there has been some experimental difficulties including a high unburned hydrocarbon carryover in the ash. In both the Florida Power Corporation and New England Electric cases the plants were originally designed to burn coal but had subsequently been converted to oil.

The situation at Florida Power & Light is that we have nine substantially similar 400 MWe oil-burning plants built in the mid 50's and early 60's which had V-bottom boilers and four 800 MWe oil-burning plants that had only recently been put on-line, or were then still under construction, which were also equipped with V-bottoms. The question was whether we could burn a coal-oil mixture of up to 50% coal in any of these plants. While we had smaller plants with which we could have experimented, we felt that we simply had to determine whether in fact we could burn the coal-oil mixture in our larger 400 or 800 MWe plants. Anything less would not significantly decrease our consumption of oil.

We were faced with a number of problems that had to be addressed early on. First, none of the plants are equipped with precipitators, although they did have dust cyclones that would remove much of the fly ash. Second, we had only recently modified the 400 MWe plants to equip them with new International Combustion Ltd. (ICL - Clark Chapman) low excess air, high efficiency burners utilizing high pressure atomization which is inappropriate for coal-oil mixutres, and hence the burners would have to be modified extensively. Our primary concerns were whether we could indeed burn a 50% coal-oil mixture in one of these plants and what its combustion characteristics would be. Specifically, we were interested in slagging and its effects on the materials in the boiler, the flame stability, the heat transfer characteristics, as well as the problems associated with handling the coal-oil mixture fuel; i.e., its stability when stored, the pumping power required, etc. We were also interested in getting a better understanding of the problems of handling the ash produced when burning coal-oil mixutres, including both the fly ash and the bottom ash.

Early on, Florida Power & Light established a number of ground rules for the proposed experimental test of coal-oil mixture in one of our 400 MWe units. First, we would not install precipitators for the test. While there was agreement that if our plants were converted for regular operation on coal-oil mixtures, we would install them, but we insisted that a variance be provided for the test. The primary reason, of course, was that this would save the $30 million associated with the installation of a precipitator and ducts that might not be needed if we did not go ahead with the conversion. This also allowed us to carry out the test about two years earlier. After extensive discussions between the Florida Department of Environmental Regulation, the Federal Environmental Protection Agency, the Florida Public Service Commisson, and Florida Power & Light, there was an agreement that the State would issue a new State Implementation Plan specifically for this test which would limit FPL to four full-power-months of operation with a coal-oil mixture. Second, a decision was made that Florida Power & Light would pay for the test burn, and that it would expect the cost involved to be absorbed in the operating expenses or be put into the rate base. The Public Service Commission eventually allowed all the cost of this experiment to be included in the fuel adjustment charge. Third, in the absence of any financial help from others, the decision was that any new technology that was developed would be proprietary to Florida Power & Light, but would be made available to others through licensing to recover some of the costs.

The decision was to utilize our 400 MWe Sanford Unit #4 located in central Florida, about 40 miles north of Orlando, and to locate the coal preparation plant immediately adjacent to it. Bechtel Engineering of Gaithersburg, MD, was chosen as the architect/engineer/constructor/operator of this coal preparation plant. There were a number of critical decisions that had to be made early in the project. Among these were the following:

1. The ability to burn 100% oil would be retained so that this plant could be utilized in our system when the coal preparation plant is shut down.

2. A high quality coal would be used, with low-sulfur, low-ash content and a high ash fusion temperature.

3. The plant was to be operated in a continuous mode with automatic measuring equipment to control the flow of pulverized coal into the oil.

4. There was to be an emphasis on stability of combustion in the burner rather than on optimizing fuel economy.

5. There would be a rapid rise in 10% increments up to 50% coal, and most of the tests would be conducted with 50% coal or as high a mixture as could be reasonably utilized.

6. Every attempt would be made to reach the full power of the plant thereby minimizing the derating associated with burning coal.

7. The emphasis would be on the burning characteristics and plant performance. There would be a minimum of experimentation.

8. Available equipment would be used where possible with a minimum of innovation in the fuel preparation plant.

9. Conventional coal grinding equipment would be used to produce pulverized coal with 80% finer than 200 mesh.

10. Additives would be used to enhance the stability of the coal in the oil.

11. Stirrers and temperature control would be incorporated into the storage tanks.

12. Nitrogen was to be used to inert pulverized coal to minimize the explosion potential.

13. Minimal coal handling and ash handling facilities would be utilized in the experiment.

International Combustion Ltd. carried out modification and testing of the burners in parallel with the construciton of the fuel preparation plant. This included the conversion from high pressure mechanical atomization to low pressure steam atomization. Burner tips were modified and hardened to minimize wear.

Because of the desire to expedite the experiment, components such as pumps were scavaged from exisitng store rooms or plants under construction and four used bowl-mill type grinding mills were purchased and installed. Six months from the time that the contract was awarded to Bechtel, the first test run was begun utilizing 10% coal-oil mixture. After a week of operation, the test moved on to 20% coal and then to 30%. The principal problems that occurred at that point was the build up of slag in the furnace and the inadequacy of the ash handling equipment. The experiment was shut down to install wall blowers in the boilers to remove the slag and to modify the ash handling facilities. Experimental work was then continued at 40%, 45%, 48% and ultimately 50% coal by weight. As the percentage of coal increased, the handling of the coal-oil mixture became more difficult, pumping power increased and the amount of wear on the equipment increased significantly. There was a problem with high temperatures on the back wall, and it was sometimes necessary to derate the unite slightly to keep this temperature within the desired limit due to inadequate fan capacity for combustion air. There was also some problems with the automatic measuring equipment that metered coal into the oil as well as with the fugitive dust raised by the portable coal-handling equipment utilized in the coal yard. The primary problem was slagging on the back wall which raised the wall temperature to the upper limit. Long term continuous operation with virtually no derating was achieved with a 42% coal-oil mixture. There were some problems with settling of the larger coal particles in the storage tank as the test progressed.

In spite of the success of this particular experiment, there are obvious drawbacks. First of all, even with a 42% coal-oil mixture only about one-third of the energy is supplied by the coal and the remaining two-thirds comes from the oil. While the prospects of being able to save 14 to 18 million barrels of oil per year is not insignificant, it still leaves FPL very dependent on imported oil. There are presently no savings in total fuel costs associated with the burning of the coal-oil mixture in this facility because of the additional cost of ash handling, the high maintenance costs associated with wear and erosion, the cost of the preparation of the mixture, the additivies and the labor involved in operating the preparation plant.

In the course of carrying out this work we have been made aware of the recent development of several new fuels involving coal, oil and water. One of these is a coal-oil-water emulsion made by putting the ingredients under high pressure in a special blender. The presence of liquid water in the blending process is postulated to serve two purposes. First it increases the fluidity of the mixture, thereby allowing a greater percentage of coal. The mechanism by which this occurs is not clear, but one postulated explanation is that the blending process breaks down the coal particles into small particles while the water "wets" the new coal surfaces, thereby serving as a "natural surfactant". Mixtures with 60% coal are available today and 70% coal mixture that would provide almost 70% of the energy from coal has been reported. Second, the finely dispersed water particles "explode" when they vaporize during combustion, thereby giving a better dispersion of the fuel and enhancing combustion.

The recent work with coal-water mixtures also appears to offer an alternate coal based liquid fuel. Some developers have reported mixtures with up to 75% coal. In this case, the penality due to the water is substantial but may be acceptable under some circumstances. Indications are that the volitility of the coal is an important factor in establishing the stability of the flame. A 25% water content would increase the gas velocity in the furnace and increase the pressure drop for a given power level. As a result there would probably be a substantial derating of the plant. This in itself is not a prohibitive impediment provided that the ability to switch rapidly to oil is retained for situations where the full output of the plant is needed by the utility.

It is instructive to take a look at the physical characteristics of coal-oil mixtures, coal-oil-water mixtures and coal-water mixtures and to apply some elementary economics to these coal based liquid fuels. First, let us look at the typical physical properties of the constituents of these mixtures as shown in Figure 1. Note that oil has more energy on a weight basis (BTU/pound) whereas coal has more energy on a volume basis (BTU/barrel).

The characteristics of four coal-oil mixtures is shown in Figure 2. As the coal content increases, the BTU content per pound decreases while the density increases. As a result the BTU content per barrel remains almost constant over the 35-50% range.

Figure 3 shows the characteristics of four coal-oil-water mixtures where the density and energy content trends are similar to those for coal-oil mixtures. However, the percent of the energy from coal is substantially greater due to the greater amount of coal present. The 70-22.5-7.5 mixture, which is considered to be achieveable on a commercial scale, has almost 70% of its energy provided by the coal.

For the four coal-water mixtures given in Figure 4, it is clear that the energy content is directly related to the percent of coal present and the energy content is markedly lower on both a weight basis and a volume basis.

Finally, complete conversion to pulverized coal should also be considered. Although this is the most expensive option since it requires a complete coal handling system, including coal storage, it is by far the most proven of the coal burning technologies. Even here, the boiler and plant modifications became more extensive when specific performance guarantees or requirements must be met.

In order to put this whole situation into perspective we have hired Ebasco to carry out a study jointly with Foster Wheeler, the manufacturer of our boilers, with the several options available to us. These studies have been individualized to each of our plants and involve both the 400 MWe and 800 MWe units. The modifications necessary for each of these options as well as the cost and the problems associated with their operation are being evaluated in this study.

Since this study is still being refined and is not yet available it is useful to carry out some "back of envelope" calculations on the economics for each of the options. For purposes of this exercise, let us assume that we have a 400 MWe plant with a 10,000 BTU/KwHr heat rate and a 60% load factor. The annual quantity and cost of both oil and coal for such a plant is given in Figure 5. Clearly the saving in fuel cost associated with conversion to coal - $76.8 million is substantial. However, there are increased operating costs (coal handling and storage, ash handling and disposal, operation of pollution equipment, etc.) and capital charges for conversion costs which must be assessed against this saving. If we assume a $5 million per year increase in operating costs and a 22% annual cost of capital, the fuel savings would appear to justify a $326 million conversion cost.

Unfortunately utility financing is not that simple due to the regulatory process imposed on most utilities. Furthermore, the cost of fuel is normally recovered immediately by the utility while the capital costs are recovered only over a period of years. Indeed, utilities are not normally allowed to put capital costs in the rate base until the next rate case after the unit comes into commercial operation, which may be months or even years later. The delicate financial status of many utilities today may preclude them from initiating any kind of capital intensive projects, even conversions that ultimately save significant fuel expenditures, because of the necessity to raise money for the project. Recent financial innovations whereby the utility is allowed to apply a fraction or all of the fuel saving against conversion capital costs may offer a way to deal with this problem.

The use of coal based liquids offers less fuel savings than pulverized coal, but the capital cost of conversion may be significantly less. Again, it is useful to use "back of envelope" calculations to scope the situation. Let us assume the fuel and processing costs shown in Table 6. By adding the costs of the constituants and processing we get the fuel costs shown in Table 7. As expected, the cost of the fuel per million BTU decreases as the percent of coal increases. From the data in Tables 5, 6 and 7 we can calculate the annual consumption and cost of fuel for oil, coal and various mixtures for the 400 MWe plant. These data are shown in Table 8.

Again, let us assume a $5 million annual increase in the operating costs for coal and the various mixtures and use the data in Table 8 and a 22% annual cost of capital to calcualte the annual savings and the associated allowable capital costs of conversion for the various fuels. These results are given in Figure 9. Our conversion cost studies are still under-way, but preliminary indications are that a conversion to pulverized coal would cost about $750 per KWe capacity or a total of $300 million for a 400 MWe plant, and a conversion to any of the mixtures without a fuel processing plant would cost about $500 per KWe capacity or a total of $200 million. These conversion costs are based on the assumption that sulphur dioxide scrubbers are not required. When these conversion costs are compared to the allowable conversion costs in Table 9, it is seen that under the assumptions of this study, the following fuel conversions may be economically feasible:

1. Pulverized Coal

2. Coal-oil-water mixtures with greater than 70% coal

3. Coal-water mixtures with greater than 60% coal

Clearly this analysis is of limited value since the assumptions dictate the final result. Furthermore, economic feasibility may not be the primary criteria if the utility is excessively vulnerable to a supply disruption. Hence, such an analyses is useful only for scoping and trend analysis.

It is also clear that this type of analysis is extremely sensitive to fuel costs and especially the difference in escalation rates. For example, let us consider the 75-25 coal-water mixture. It is readily shown that an increase from \$55.00 to \$63.47 per ton of coal (15.4%), a decrease in the price of oil from \$35.00 per barrel to \$32.84 per barrel (6.1%), an increase in the conversion cost of \$34.1 million (17.1%), or an increase in the processing costs from \$15.00 per ton to \$21.94 per ton (46.3%) would make conversion to this fuel economically unfeasible. All of these changes are clearly within the realm of possibility.

FPL has carried out a preliminary engineering study of converting the Sanford-5 plant (substantially identical to the Sanford-4 plant used in the coal-oil mixture test) to pulverized coal, and a detailed engineering study is contemplated later this year. In the mean time an accelerated testing program (including combustion tests) to evaluate the physical and chemical characteristics of coal-oil-water and coal water mixtures has been initiated. It is our expectation that this evaluation program will demonstrate the technological feasibility of burning a coal based liquid (COW or CWM) in our plants and define the changes in our power plants necessary to accomodate these fuels. This then should provide a valid basis for evaluating the economic feasibility of using these coal based liquids. At the present time the uncertainties in the costs and benefits of conversion are so large that a decision on conversion cannot be made without further refinement if the decision is based only on economic considerations. Our present R&D program is designed to reduce these uncertainties, thereby providing greater confidence in the decision process.

There is one cloud that hangs over this whole operation which lends considerable uncertainty to the cost, as well as the feasibility of proceeding with any of the options, and this is the regulatory situation. The present regulations require that any existing plant which is modified significantly must be made to meet new source performance standards. This would include not only precipitators (or bag houses if the fine particulate standards are tightened) but also SO_2 scrubbers which are mandated by current regulations almost irrespective of the sulfur content of the fuel. While EPA indicates that they would consider each application for an exemption on its own merits, they gave no indication that they are willing to waive this requirement to meet new source performance standards simply to reduce the amount of oil being burned. Our position has consistently been that the existing standards for existing plants should continue in effect after a conversion to coal derived fuels rather than be ratcheted into meeting new source performance standards. Indeed our studies show that if new source performance standards must be met at existing plants, the only rational route from an economic standpoint is to continue burning oil, or abandon the existing plants and to build new pulverized coal plants if oil is simply not available. Again, we have the classic confrontation between two separate Federal agencies. EPA is primarily interested in protecting the environment at the exclusion of all other interests and the Department of Energy is primarily interested in reducing the amount of oil burned in generating electricity, thereby reducing oil imports.

In summary, we have demonstrated the feasibility of burning coal-oil mixtures in a 400 MWe plant designed originally to burn oil. Studies are continuing with ~~plans being made to conduct some tests on coal-water mixture, coal-oil-water mixtures~~ and pulverized coal. There is a common wisdom that if you can burn pulverized coal alone it is by far the most economical route. However, this may be a near-sighted view, not taking into account all the environmental consequences and associated costs. We are continuing this work with the expectation that it will lead to a decision in the next year or two whereby at least some of our large oil burning plants will be converted over to coal or some coal-based liquid fuel.

TABLE 1 - PROPERTIES OF COAL, OIL AND WATER

	% ENERGY FROM COAL	LB/FT^3	BTU/LB	LB/BBL	BTU/BBL
Coal	100	90	13000	505	6.56×10^6
Oil	0	60	18000	337	6.06×10^6
Water	0	60	0	337	0

TABLE 2 - PROPERTIES OF COAL-OIL MIXTURES

COMPOSITION Wt.% COAL-OIL	% ENERGY FROM COAL	LB/FT^3	BTU/LB	LB/BBL	BTU/BBL
35-65	28.0%	70.5	16250	396	6.44×10^6
40-60	32.5%	72.0	16000	404	6.47×10^6
45-55	37.1%	73.5	15750	413	6.50×10^6
50-50	41.9%	75.0	15500	421	6.53×10^6

TABLE 3 - PROPERTIES OF COAL-OIL-WATER MIXTURES

COMPOSITION Wt.% COAL-OIL-WATER	% ENERGY FROM COAL	LB/FT^3	BTU/LB	LB/BBL	BTU/BBL
50-45-5	44.5	75.0	14600	421	6.15×10^6
60-35-5	55.3	78.0	14100	438	6.17×10^6
70-22.5-7.5	69.2	81.0	13150	455	5.98×10^6
80-10-10	85.2	84.0	12200	472	5.75×10^6

TABLE 4 - PROPERTIES OF COAL-WATER MIXTURES

COMPOSITION Wt.% COAL-WATER	% ENERGY FROM COAL	LB/FT^3	BTU/LB	LB/BBL	BTU/BBL
60-40	100.0	78.0	7800	438	3.42×10^6
70-30	100.0	81.0	9100	455	4.14×10^6
75-25	100.0	82.5	9750	463	4.51×10^6
80-20	100.0	84.0	10400	472	4.91×10^6

TABLE 5 - CHARACTERISTICS OF POWER PLANT

Capacity	400 MWE
Heat Rate	10,000 BTU/KwHr
Duty Cycle	60%
Annual Output	2.10×10^9 KwHr/Yr
Annual Input	2.10×10^{13} BTU/Yr
Coal Consumption (with 13,000 BTU/LB Coal)	8.08×10^5 Tons/Yr
Oil Consumption (with 18,000 BUT/LB Oil)	3.47×10^6 BBL/Yr
Coal Cost ($55/Ton)	$\$44.5 \times 10^6$/Yr
Oil Cost ($35/BBL)	$\$121.3 \times 10^6$/Yr
ANNUAL FUEL SAVINGS FOR COAL	$\$76.8 \times 10^6$/Yr

TABLE 6 - FUEL AND PROCESSING COSTS

Coal	$55.00/Ton
Oil	$35.00/BBL
Processing COM	$10.00/Ton
Processing COW	$12.00/Ton
Processing CWM	$15.00/Ton

TABLE 7 - COST OF FUEL

	COMPOSITION	$/BBL	$/MMBTU
Oil	0-100	35.00	5.78
Coal	100-0	13.89	2.12
COM	35-65	29.58	4.59
	40-60	28.57	4.42
	45-55	27.56	4.24
	50-50	26.55	4.07
COW	50-45-5	25.22	4.10
	60-35-5	23.20	3.76
	70-22.5-7.5	20.33	3.40
	80-10-10	17.83	3.10
CWM	60-40	11.62	3.40
	70-30	13.13	3.17
	75-25	13.88	3.08
	80-20	14.64	2.98

TABLE 8 - ANNUAL CONSUMPTION, COST OF FUEL

	COMPOSITION	BBL/YEAR	$/YEAR COST
Oil	0-100	3.47×10^6	121.3×10^6
Coal	100-0	3.20×10^6*	44.5×10^6
COM	35-65	3.26×10^6	96.4×10^6
	40-60	3.25×10^6	92.9×10^6
	45-55	3.23×10^6	89.1×10^6
	50-50	3.22×10^6	85.5×10^6
COW	50-45-5	3.41×10^6	86.0×10^6
	60-35-5	3.40×10^6	78.9×10^6
	70-22.5-7.5	3.51×10^6	71.4×10^6
	80-10-10	3.65×10^6	65.1×10^6
CWM	60-40	6.14×10^6	71.3×10^6
	70-30	5.07×10^6	66.6×10^6
	75-25	4.66×10^6	64.7×10^6
	80-20	4.28×10^6	62.7×10^6

* 8.09×10^5 TONS/YR

TABLE 9 - ANNUAL SAVINGS AND ALLOWABLE CONVERSION COSTS

	COMPOSITION	ANNUAL SAVINGS	ALLOWABLE CONVERSION COSTS
Oil	0-100	0	0
Coal	100-0	$\$71.8 \times 10^6$	326.4×10^6
COM	35-65	$\$19.9 \times 10^6$	$\$90.5 \times 10^6$
	40-60	$\$23.4 \times 10^6$	$\$106.4 \times 10^6$
	45-55	$\$27.2 \times 10^6$	$\$123.6 \times 10^6$
	50-50	$\$30.8 \times 10^6$	$\$140.0 \times 10^6$
COW	50-45-5	$\$30.3 \times 10^6$	$\$137.7 \times 10^6$
	60-35-5	$\$37.4 \times 10^6$	$\$170.0 \times 10^6$
	70-22.5-7.5	$\$44.9 \times 10^6$	$\$204.1 \times 10^6$
	80-10-10	$\$51.2 \times 10^6$	$\$232.7 \times 10^6$
CWM	60-40	$\$45.0 \times 10^6$	$\$204.5 \times 10^6$
	70-30	$\$49.7 \times 10^6$	$\$225.9 \times 10^6$
	75-25	$\$51.5 \times 10^6$	$\$234.1 \times 10^6$
	80-20	$\$53.6 \times 10^6$	$\$243.6 \times 10^6$