6.0 YIELD, CAPITAL AND OPERATING COST ESTIMATES

This section documents the preparation of commercial yield, capital and operating cost estimates. One objective of this program is to quantify the economic advantage of low pressure reforming (50 psig) over a typical first generation CCR Platforming process pressure (125 psig). Another goal of this program is to choose between two naphtha upgrading routes (Figures 6.1 and 6.2). One route is processing the full-boiling-range (FBR) naphtha, the other is splitting the FBR naththa into light and heavy cuts, then processing each cut separately. The final goal is to examine the effect of naphtha source on reforming economics. Estimates provided in this section will be used to address all three issues, within the economic evaluation of Section 7.

6.1 FEEDSTOCK DEFINITIONS FOR YIELD ESTIMATES

Naphthas produced by two different F-T reactor technologies, Arge and Synthol, were defined based on a literature report (9). A constant basis of 40,000 BPSD of F-T naphtha (C_6-C_{11}) was chosen for this study. The intent is to focus on process technologies rather than on economies of scale. The units discussed in this report are all large enough to avoid anomalies resulting from evaluating an unusually small unit. In actuality, the Synthol technology would make more naphtha than Arge technology because the former is designed to maximize gasoline production, thus the Synthol-based facility would be larger.

6.1.1 Arge Naphtha

Arge synthesis is designed to maximize middle distillate. An Arge reactor produces straight chain molecules. After hydrotreating, Arge naphtha contains approximately 95 wt-% normal paraffins and 5 wt-% branched paraffins. A carbon number distribution was calculated by assuming a F-T chain growth probability of 0.95. The resulting full-boiling range (FBR) naphtha is described in Table 6.1. Light and heavy cuts of this naphtha were defined based on a perfect split between C_8 and C_9 (Tables 6.2 and 6.3).

6.1.2 Synthol Naphtha

Synthol technology is designed to maximize naphtha yield, and therefore gasoline production. Unlike Arge naphtha, Synthol naphtha has aromatics. After hydrotreating, the Synthol naphtha described in the literature would have approximately 15 wt-% aromatics and about 85 wt-% paraffins. A second distinction between the naphthas is the high degree of branching of Synthol products. About 43 wt-% of the Synthol paraffins would be branched as opposed to 5 wt-% of the Arge paraffins.

A carbon number distribution was calculated by assuming a F-T chain growth probability of 0.70. The resulting full-boiling range (FBR) naphtha is described in Table 6.4. Light and heavy cuts of this naphtha were defined based on a perfect split between C_8 and C_9 (Tables 6.5 and 6.6).

6.2 COMMERCIAL YIELD ESTIMATES

A yield estimate makes the transition from pilot plant data to a prediction of commercial performance. Input to the commercial yield estimate includes catalytic activity, stability, and product selectivity data obtained in the pilot plant. Output from the commercial yield estimate includes mass-balanced yields and catalyst requirements.

As previously stated, the yield estimates listed in Table 6.7 accomplish three main objectives:

1. Quantify the advantage of lowering reformer pressure from 125 psig to 50 psig.
2. Provide input into an economic evaluation, designed to choose between the two naphtha upgrading routes considered in this program (FBR or split-naphtha routes).

3. Compare the effect of F-T synthesis technology on naphtha upgrading economics. The two naphtha sources and two naphtha upgrading options define four cases:

   Case 1, FBR Arge naphtha processing
   Case 2, Split Arge naphtha processing
   Case 3, FBR Synthol naphtha processing
   Case 4, Split Synthol naphtha processing

6.2.1 CCR Platforming Process Yield Estimates

Seven CCR Platforming process yield estimates are compared. Five estimates for Arge derived naphtha are grouped together in Table 6.8, and the two Synthol naphtha estimates are combined in Table 6.9.

The yield advantage of low pressure is estimated for Arge FBR naphtha (YE nos. 1 and 2). The reduction of reactor pressure from 125 psig to 50 psig increases C_5+ liquid volume yield from 69.1% to 74.5%. There is a corresponding hydrogen yield increase from 1418 SCFB to 1807 SCFB. Similar yield advantages are estimated for Arge heavy naphtha (YE nos. 3 and 4).

One CCR Platforming process yield estimate was prepared for a light Arge naphtha. This estimate is solely for comparison to the light naphtha Platforming process yield estimates, described in Section 6.2.2, and will not be used in the economic analysis.

FBR and heavy-Synthol naphtha yield estimates were generated at 50 psig reactor pressure (Table 6.9). There is a small yield advantage in each case for Synthol naphtha. The Synthol feeds have 15 wt-% aromatics, and these are easier to process in the reformer than the Arge naphtha. The yield difference is the result of competing reactions. The conversion of paraffins to aromatics results in volumetric shrinkage which favors Synthol naphtha yields. Branched paraffins undergo more hydrocracking to light gases than linear paraffins which favor Arge naphtha yields.

6.2.2 Light Naphtha Platforming Process Yield Estimates

Two light naphtha yield estimates were made (Table 6.10). Estimates for light Arge and Synthol naphthas (C_6-C_8) provide input for the split-naphtha cases defined in Section 6.2.1.

6.3 CAPITAL AND OPERATING COST ESTIMATES

The yield estimate serves as the basis for preparation of the estimated erected cost (EEC). The EEC is a collection of process component costs. The major components of the Platforming process are the reactor, charge and interheaters, product condenser, product separator, compressor, product debutanizer, and catalyst regeneration sections. The EEC also includes detailed engineering and construction expenses (contractor fees, etc.).

The capital cost of the reactor section depends on the feed rate and reactor pressure. The compressor cost is largely a function of process pressure and compressor capacity. Compressor and driver capital costs are very significant in most refinery processes and may comprise up to 25% of the inside battery limits (ISBL) EEC.

Operating costs are determined by information in the yield estimate, and are largely a function of unit capacity. Other costs such as maintenance, property taxes, and insurance were estimated as a percentage of the EEC.

Capital and operating cost estimates for the process-pressure comparison are summarized in Table 6.11. Capital and operating cost estimates related to the FBR and split-naphtha processing options are summarized in Table 6.12. All the estimates are used as inputs to the economic analyses in Section 7.

TABLE 6.1

Arge FBR Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	0.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	0.70	0.660	1.06	0.75
n-C6	14.00	0.664	21.08	14.94
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	0.00	0.884	0.00	0.00
i-C7	0.80	0.680	1.18	0.83
n-C7	15.10	0.688	21.94	15.55
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	0.00	0.872	0.00	0.00
i-C8	0.80	0.700	1.14	0.81
n-C8	15.80	0.707	22.35	15.84
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	0.00	0.870	0.00	0.00
i-C9	0.90	0.720	1.25	0.89
n-C9	16.40	0.718	22.85	16.20
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	0.00	0.900	0.00	0.00
i-C10	0.90	0.741	1.21	0.86
n-C10	16.70	0.730	22.88	16.21
C10 Naph	0.00	0.795	0.00	0.00
i-C11	0.90	0.752	1.20	0.85
n-C11	17.00	0.740	22.97	16.28
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		141.11	100.00

Specific Gravity	0.7087
API Gravity	68.17

	wt-%	vol-%
P	100.0	100.0
O	0.0	0.0
N	0.0	0.0
A	0.0	0.0

TABLE 6.2

Arge Light Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	0.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	1.60	0.660	2.42	1.66
n-C6	29.60	0.664	44.58	30.60
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	0.00	0.884	0.00	0.00
i-C7	1.70	0.680	2.50	1.72
n-C7	31.90	0.688	46.35	31.82
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	0.00	0.872	0.00	0.00
i-C8	1.80	0.700	2.57	1.77
n-C8	33.40	0.707	47.24	32.43
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	0.00	0.870	0.00	0.00
i-C9	0.00	0.720	0.00	0.00
n-C9	0.00	0.718	0.00	0.00
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	0.00	0.900	0.00	0.00
i-C10	0.00	0.741	0.00	0.00
n-C10	0.00	0.730	0.00	0.00
C10 Naph	0.00	0.795	0.00	0.00
i-C11	0.00	0.752	0.00	0.00
n-C11	0.00	0.740	0.00	0.00
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		145.66	100.00

Specific Gravity	0.6865
API Gravity	74.61

	wt-%	vol-%
P	100.0	100.0
O	0.0	0.0
N	0.0	0.0
A	0.0	0.0

TABLE 6.3

Arge Heavy Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	0.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	0.00	0.660	0.00	0.00
n-C6	0.00	0.664	0.00	0.00
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	0.00	0.884	0.00	0.00
i-C7	0.00	0.680	0.00	0.00
n-C7	0.00	0.688	0.00	0.00
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	0.00	0.872	0.00	0.00
i-C8	0.00	0.700	0.00	0.00
n-C8	0.00	0.707	0.00	0.00
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	0.00	0.870	0.00	0.00
i-C9	1.60	0.720	2.22	1.62
n-C9	31.10	0.718	43.34	31.62
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	0.00	0.900	0.00	0.00
i-C10	1.70	0.741	2.29	1.67
n-C10	31.70	0.730	43.42	31.69
C10 Naph	0.00	0.795	0.00	0.00
i-C11	1.70	0.752	2.26	1.65
n-C11	32.20	0.740	43.51	31.75
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		137.05	100.00

Specific Gravity	0.7297
API Gravity	62.42

	wt-%	vol-%
P	100.0	100.0
O	0.0	0.0
N	0.0	0.0
A	0.0	0.0

TABLE 6.4

Branched-Paraffin FBR Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	C.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	9.90	0.660	15.00	10.79
n-C6	13.00	0.664	19.58	14.08
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	4.10	0.884	4.64	3.34
i-C7	8.10	0.680	11.91	8.57
n-C7	10.70	0.688	15.55	11.18
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	3.30	0.872	3.78	2.72
i-C8	6.50	0.700	9.29	6.68
n-C8	8.60	0.707	12.16	8.75
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	2.60	0.870	2.99	2.15
i-C9	5.10	0.720	7.08	5.09
n-C9	6.70	0.718	9.34	6.71
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	5.00	0.900	5.56	4.00
i-C10	4.00	0.741	5.40	3.88
n-C10	5.20	0.730	7.12	5.12
C10 Naph	0.00	0.795	0.00	0.00
i-C11	3.10	0.752	4.12	2.96
n-C11	4.10	0.740	5.54	3.98
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		139.06	100.00

Specific Gravity	0.7191
API Gravity	65.27

	wt-%	vol-%
P	85.0	87.8
O	0.0	0.0
N	0.0	0.0
A	15.0	12.2

TABLE 6.5

Branched-Paraffin Light Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	0.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	14.80	0.660	22.42	15.78
n-C6	19.60	0.664	29.52	20.78
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	6.00	0.884	6.79	4.78
i-C7	12.10	0.680	17.79	12.53
n-C7	16.00	0.688	23.25	16.36
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	5.00	0.872	5.73	4.04
i-C8	9.70	0.700	13.86	9.75
n-C8	12.80	0.707	18.10	12.74
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	4.00	0.870	4.60	3.24
i-C9	0.00	0.720	0.00	0.00
n-C9	0.00	0.718	0.00	0.00
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	0.00	0.900	0.00	0.00
i-C10	0.00	0.741	0.00	0.00
n-C10	0.00	0.730	0.00	0.00
C10 Naph	0.00	0.795	0.00	0.00
i-C11	0.00	0.752	0.00	0.00
n-C11	0.00	0.740	0.00	0.00
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		142.06	100.00

Specific Gravity	0.7039
API Gravity	69.52

	wt-%	vol-%
P	85.0	87.9
O	0.0	0.0
N	0.0	0.0
A	15.0	12.1

TABLE 6.6

Branched-Paraffin Heavy Naphtha

	wt-%	SG	cc	vol-%
Olefins	0.00	0.700	0.00	0.00
n-C4	0.00	0.584	0.00	0.00
i-C5	0.00	0.624	0.00	0.00
n-C5	0.00	0.631	0.00	0.00
i-C6	0.00	0.660	0.00	0.00
n-C6	0.00	0.664	0.00	0.00
C6 Naph	0.00	0.783	0.00	0.00
A6 Arom	0.00	0.884	0.00	0.00
i-C7	0.00	0.680	0.00	0.00
n-C7	0.00	0.688	0.00	0.00
C7 Naph	0.00	0.774	0.00	0.00
A7 Arom	0.00	0.872	0.00	0.00
i-C8	0.00	0.700	0.00	0.00
n-C8	0.00	0.707	0.00	0.00
C8 Naph	0.00	0.780	0.00	0.00
A8 Arom	0.00	0.870	0.00	0.00
i-C9	15.40	0.720	21.39	16.08
n-C9	20.40	0.718	28.43	21.37
C9 Naph	0.00	0.794	0.00	0.00
A9+ Arom	15.00	0.900	16.67	12.53
i-C10	12.00	0.741	16.20	12.18
n-C10	15.80	0.730	21.64	16.27
C10 Naph	0.00	0.795	0.00	0.00
i-C11	9.20	0.752	12.23	9.20
n-C11	12.20	0.740	16.48	12.39
C11 Naph	0.00	0.800	0.00	0.00
C12+	0.00	0.890	0.00	0.00
Total	100.00		133.04	100.00

Specific Gravity	0.7516
API Gravity	56.76

	wt-%	vol-%
P	85.0	87.5
O	0.0	0.0
N	0.0	0.0
A	15.0	12.5

TABLE 6.7

Platforming Process Yield Estimates

No.	Naphtha	Platforming Process Type	Rx Pressure, psig
1	Arge FBR	CCR	125
2	Arge FBR	CCR	50
3	Arge Hvy.	CCR	125
4	Arge Hvy.	CCR	50
5	Arge Lt.	CCR	50
6	Synthol FBR	CCR	50
7	Synthol Hvy.	CCR	50
8	Arge Lt.	Light Naphtha	--
9	Synthol Lt.	Light Naphtha	--

TABLE 6.8

CCR Platforming Process Yield Estimates for Arge Naphthas

	Yield Estimate Number				
	1	2	3	4	5
Feedstock					
Naphtha Source	Arge	Arge	Arge	Arge	Arge
Naphtha Type	FBR	FBR	Heavy	Heavy	Light
API	68.2	68.2	62.4	62.4	74.6
Carbon No. Range	6-11	6-11	9-11	9-11	6-8
Paraffins, vol-%	100	100	100	100	100
Naphthenes, vol-%	0	0	0	0	0
Aromatics, vol-%	0	0	0	0	0
Operating Conditions					
Feedrate, BPSD	40,000	40,000	20,500	20,500	19,500
LHSV, 1/hr	LHSV-A	LHSV-A	LHSV-A	LHSV-A	LHSV-A
H_2/HC, molar (a)	HHC-A	HHC-A	HHC-A	HHC-B	HHC-A
Rx Pressure, psig	125	50	125	50	125
C_5+ RONC	100	100	100	100	98
Continuous Yields					
C_5+, vol-%	69.1	74.5	72.6	76.8	75.7
Hydrogen, SCFB	1,418	1,807	1,618	1,997	1,691
C_5+, wt-%	76.9	83.3	79.9	84.8	84.4
Hydrogen, wt-%	3.0	3.9	3.4	4.1	3.7
C_1-C_4, wt-%	20.1	12.8	16.7	11.1	11.9

Note:

(a) HHC-B is 35% greater than HHC-A.

TABLE 6.9

CCR Platforming Process Yield Estimate for Synthol Naphthas

	Yield Estimate Number	
	6	7
Feedstock		
Naphtha Source	Synthol	Synthol
Naphtha Type	FBR	Heavy
API	65.3	56.8
Carbon No. Range	6-11	9-11
Paraffins, vol-%	87.8	87.5
Naphthenes, vol-%	0.0	0.0
Aromatics, vol-%	12.2	12.5
Operating Conditions		
Feedrate, BPSD	40,000	12,700
LHSV, 1/hr (a)	LHSV-B	LHSV-B
H_2/HC, molar (b)	HHC-A	HHC-C
Rx Pressure, psig	50	50
C_5+ RONC	100	100
Continuous Yields		
C_5+, vol-%	75.0	77.3
Hydrogen, SCFB	1,318	1,456
C_5+, wt-%	83.3	84.3
Hydrogen, wt-%	2.8	2.9
C_1-C_4, wt-%	13.9	12.8

Notes:

(a) LHSV-B is 60% greater than LHSV-A (Table 6.8).

(b) HHC-C is 55% greater than HHC-A, and 15% greater than HHC-B (Table 6.8).

TABLE 6.10

Light Naphtha Platforming Process Yield Estimates

	Yield Estimate Number	
	8	9
Feedstock		
Naphtha Source	Arge	Synthol
Naphtha Type	Light	Light
API	74.6	69.5
Carbon No. Range	6-8	6-8
Paraffins, vol-%	100.0	87.9
Naphthenes, vol-%	0.0	0.0
Aromatics, vol-%	0.0	12.1
Operating Conditions		
Feedrate, BPSD	19,500	27,300
C_5+ RONC	104	105
Yields		
C_5+, vol-%	70.9	73.1
Hydrogen, SCFB	2,530	2,410
C_5+, wt-%	86.4	87.3
Hydrogen, wt-%	5.6	5.3
C_1-C_4, wt-%	8.0	7.4

TABLE 6.11

Capital and Operating Cost Estimates
for Low and High Pressure Reforming Units

	Relative Process Pressure	
	Low	High
Naphtha Source	Arge	Arge
Process Scheme	FBR	FBR
Rx Pressure, kg/cm^2 (psig)	3.5 (50)	8.8 (125)
ISBL Capital Costs, MM $		
Naphtha Splitter	0.0	0.0
CCR Platforming Unit	31.5	29.1
Light Naphtha Platforming Unit	0.0	0.0
Total ISBL EEC	31.5	29.1
Unit Capacities		
BPSD	40,000	40,000
MT/SD	4,507	4,507
CCR Platforming Unit Utilities (a)		
Electricity, kW	9,764	4,526
HP Steam, MT/hr	(32.9)	(31.2)
MP Steam, MT/hr	0.5	0.6
BFW, MT/hr	47.8	40.2
Condensate, MT/hr	(12.8)	(7.2)
Cooling Water, MT/hr	566	465
Fuel Fired, GJ/hr	381.1	338.3

(a) Negative value indicates utility export

TABLE 6.12

Capital and Operating Cost Estimates
for FBR and Split-Naphtha Processing Schemes

	Case Number			
	1	2	3	4
Naphtha Source Process Scheme	Arge FBR	Arge Split	Synthol FBR	Synthol Split
ISBL Capital Costs, MM $				
Naphtha Splitter	0.0	2.8	0.0	2.8
CCR Platforming Unit	31.5	21.4	28.6	18.2
Light Naphtha Platforming Unit	0.0	16.5	0.0	20.9
Total ISBL EEC	31.5	40.7	28.6	41.9
Unit Capacities				
CCR Platformer unit, BPSD	40,000	20,500	40,000	12,700
CCR Platformer unit, MT/SD	4,507	2,379	4,573	1,519
Light naphtha unit, BPSD	0	19,500	0	27,300
Light naphtha unit, MT/SD	0	2,128	0	3,054
CCR Platforming Unit Utilities (a)				
Electricity, kW	9,764	5,528	8,107	2,733
HP Steam, MT/hr	(32.9)	(16.0)	(25.5)	(6.7)
MP Steam, MT/hr	0.5	0.3	0.5	0.2
BFW, MT/hr	47.8	25.3	43.0	14.1
Condensate, MT/hr	(12.8)	(8.2)	(15.3)	(6.9)
Cooling Water, MT/hr	566	292	592	185
Fuel Fired, GJ/hr	381.1	200.5	347.9	115.1
Lt. Naph. Platforming Unit Utilities (b)				
Electricity, kW	0	3,944	0	4,474
HP Steam, MT/hr	0	(15.5)	0	(17.0)
MP Steam, MT/hr	0	0.2	0	0.4
BFW, MT/hr	0	22.6	0	28.7
Condensate, MT/hr	0	(6.0)	0	(10.2)
Cooling Water, MT/hr	0	267	0	375
Fuel Fired, GJ/hr	0	240.0	0	292.4
Total Utilities				
Electricity, kW	9,764	9,472	8,107	7,207
HP Steam, MT/hr	(32.9)	(31.5)	(25.5)	(23.7)
MP Steam, MT/hr	0.5	0.5	0.5	0.6
BFW, MT/hr	47.8	47.9	43.0	42.8
Condensate, MT/hr	(12.8)	(14.2)	(15.3)	(17.0)
Cooling Water, MT/hr	566	559	592	561
Fuel Fired, GJ/hr	381.1	440.5	347.9	407.5

(a) Negative value indicates utility export
(b) Includes naphtha splitter utilities

FIGURE 6.1

FULL-BOILING-RANGE NAPHTHA PROCESSING

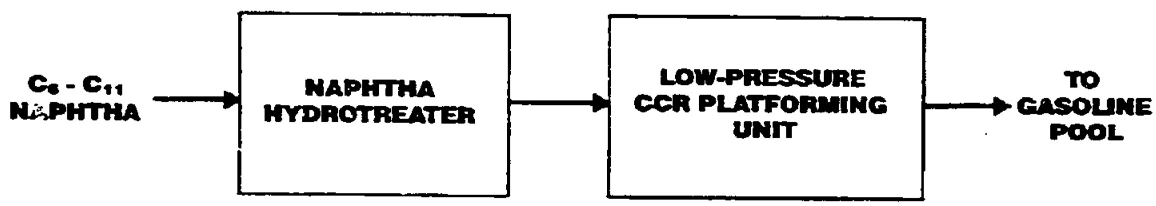
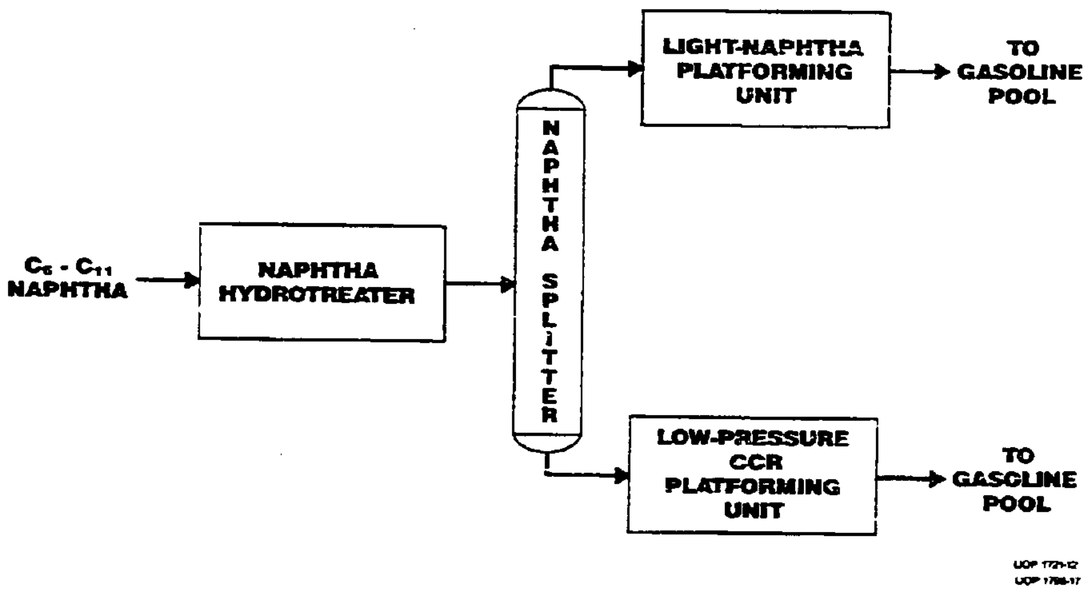


FIGURE 6.2

SPLIT-NAPHTHA PROCESSING



7.0 ECONOMIC EVALUATION

The economic evaluation is intended to achieve three objectives. First, quantify the economic advantage achieved by reforming F-T naphtha at low pressure. Second, compare the effect of naphtha compositions produced by two different F-T technologies, Arge and Synthol, on reforming economics. Finally, evaluate a choice between FBR and split-naphtha flow schemes.

7.1 EVALUATION PROCEDURE

The economic evaluation is the culmination of a series of steps (Figure 7.1). The pilot plant work demonstrates technical feasibility and provides data for yield estimates. Process conditions are optimized and translated to commercial scale in the yield estimating step. Outputs from the yield estimates are used to predict capital and operating costs.

After the first three steps are complete, enough information is generated to permit an economic evaluation. However, even with this much information, the evaluation is only preliminary in nature. The capital cost estimates are arrived at by using cost curves as well as other estimation techniques. Detailed engineering for each case is not warranted at this point. The preliminary economic evaluation is sufficient for the three goals identified for the economic evaluation.

7.1.1 Evaluation Technique

Capital requirements, operating costs, feedstock costs and product values are inputs to the economic evaluation. The evaluation revolves around two capital budgeting questions. First, do the timing and magnitude of operating profits justify the capital expenditure? Second, how does this expenditure compare to mutually exclusive alternatives?

Many procedures are available to assist a capital budgeting decision. Pay-back period and return on investment (ROI) are commonly used as a first approximation. Other methods, such as discounted internal rate of return (IRR) and net present value (NPV), are more rigorous because they consider the time value of money and offer a clear decision rule. In this report, IRR is used.

To determine an IRR, capital charges and operating profits are considered in terms of present value at unit start-up ($t = 0$). The IRR is the discount rate applied to operating profits that creates a present value (PV) of profits equal to the capital expenditure (Figure 7.2). The greater the IRR, the more profitable the operation. If feedstock costs and product values are known, IRR can be determined directly. If either the feedstock cost or product value is uncertain (one must be specified), the IRR can be fixed at a minimum acceptable percentage (hurdle rate) before solving the equation. The result indicates how low feedstock costs or how high product values must be to ensure the minimum IRR.

Sensitivity analyses are also useful to perform. IRR can be determined over a range of naphtha costs, reformate values and hydrogen co-product values.

7.1.2 Price and Cost Basis for Economic Evaluation

Feedstock, product and utility prices used in this evaluation are reasonably accurate for a scenario in which the price for oil is $18-19 per barrel. The prices used are explicitly stated within each analysis.

Hydrogen may be valued anywhere between fuel gas (on an equivalent Btu basis) and its chemical value. The value is largely determined by the overall hydrogen needs of the complex in question. An intermediate value between fuel gas and chemical hydrogen was chosen for this evaluation (except for the sensitivity analysis).

7.1.3 Fuel Gas Production and Consumption

Some of the fuel gas produced within the Platforming unit can be used in fired heaters. For this reason, fuel gas is treated as a product (naturally, not the desired product), and total energy requirements are treated as a cost. The fuel gas product value credit is offset by the utility requirements (listed as "Fuel Fired" in the utility estimates, Table 6.11). The fuel cost ($2.61/GJ) is priced to match the fuel gas value ($131/MT) so that process economics is not affected. The implied heating value for the fuel is 50.2 GJ/MT, which is consistent with a refinery fuel gas.

7.1.4 Treatment Of Offsites

An allowance for offsite expenditure of 40% of the ISBL total was used in each case.

7.2 CAPITAL COST AND NET OPERATING PROFIT CALCULATIONS

This section describes the treatment of capital costs and the determination of operating profits. Assumptions implicit in each category are discussed.

7.2.1 Capital Expenditure

The largest component of total capital requirement is the capitalized EEC. Construction is assumed to spread over a three-year interval, with 20%, 50% and 30% of the total capital expended each year, respectively. Capital expenditure in the first and second years does not generate revenue until start-up. To account for this fact, an interest rate, compounded annually, is charged to reflect an opportunity cost. The alternative investment rate for these sunk funds is 10%. Applying the interest charges gives the present value of EEC capital at the time of unit start-up.

Aside from the capitalized EEC, the initial catalyst loading is added to the capital requirement, assuming that the catalyst arrives onsite just prior to start-up.

An assumption is made that the project is 100% equity financed for the purpose of making a capital budgeting decision. Debt financing has implications on the debt/equity structure and therefore the cost of capital. For IRR calculations, it is not necessary to assume a cost of capital. Typically, the IRR is compared to the cost of capital in order to make "go or no-go" decisions. In this report, IRR's from mutually exclusive alternatives are compared in order to choose the better alternative. The implication of 100% equity financing in this case is that the interest charges added to the EEC (to arrive at a capitalized EEC) are not subtracted from income or depreciated in any form. The equity financing assumption is consistent with the goal of making the best possible capital budgeting decision. After the best alternative (including the "do-nothing" alternative) is identified, specific decisions regarding how the project is actually financed can be made independently.

7.2.2 Gross Margin

Gross margin is the value added to the fresh feed as a result of processing. The key inputs to the gross-margin calculation are the mass balanced yields from Section 6 and the feedstock cost and product value assumptions. Mass flow rates are converted to dollar flow rates. The result is a net value added to the feed expressed in dollars per unit time.

The operating year is defined as 355 days, reflecting a high on-stream efficiency that has been demonstrated by the CCR Platforming process.

7.2.3 Operating Cost

Operating cost is the sum of variable and fixed costs.

Operating cost is subtracted from gross margin to obtain the net operating profit.

7.2.3.1 Catalyst and Chemicals

The initial catalyst loadings are treated as a capital requirement, but reloads are treated as a variable cost of production. Catalyst cost and the expected catalyst life define a series of cash flows for catalyst replacement over the project life (20 years). Annual sinking-fund payments that are sufficient to cover all catalyst reloads are determined. The purpose of this procedure is to annualize expenditures that do not necessarily occur each year. Reforming catalysts contain platinum, which is recovered from spent catalyst. Catalyst charges do not include the platinum value. The platinum inventory is included as working capital, and a 10% annual interest charge is assessed.

The Platforming process is a moving catalyst system. An estimate of catalyst loss as a result of attrition is included in the annualized catalyst replacement cost. Some nitrogen is consumed by the catalyst transfer equipment, and this chemical cost is also considered.

7.2.3.2 Utilities

Utility estimates from Section 6 were combined with the utility cost assumptions and expressed in dollars per unit time.

7.2.3.3 Labor

It is assumed that two operators and one boardman would be required for each shift. A base wage rate of $15/hr is assumed. The labor estimate is for continuous coverage (24 hours a day, 365 days per year) and includes an allowance for vacations, holidays and sick days (allowance of 15% of total work time). Supervision costs are assumed to be 25% of labor costs. Total labor costs, including supervision, are multiplied by a factor of 1.35 to account for fringe benefits. Finally, this product is multiplied by a factor of 1.5 to account for overhead, such as computer, laboratory and administrative charges.

7.2.3.4 Maintenance

An allowance of 2% of the EEC was established as the estimate for maintaining the process unit. Maintenance labor and spare parts inventory charges are included in this estimate.

7.2.3.5 Taxes and Insurance

An allowance of 1.5% of the EEC was established as the estimate for state and local taxes (property taxes, for example) and hazard insurance covering the unit.

7.3 IRR CALCULATIONS

As mentioned previously, IRR calculations compute the discount rate that may be applied to operating profits so that their present value equals the present value of capital expenditure at unit start-up. The higher the discount rate (or internal return) the more attractive the project.

7.3.1 Income Tax Considerations

IRR's may be determined before or after income tax is figured. The more meaningful comparisons are on an after-tax basis. However, because tax rates vary widely and depend on many factors, before-tax IRR's are also presented.

For after-tax IRR's, the corporate tax rate is assumed to be 33%. Depreciation also enters into the after-tax cash flows because it is subtracted from net operating profit when determining the tax li-

[redacted]

ability. Straight-line depreciation over a ten-year time span is used throughout. However, depreciation is not a cash flow. It has absolutely no impact on before-tax profits.

No investment credits are assumed for this study. Neither price support nor any special pricing arrangement for raw materials is considered.

7.4 SUMMARY OF IRR ANALYSES

7.4.1 Effect of Pressure Reduction

The analysis presented in Table 7.1 reveals that 50 psig reactor operation yields a significantly better IRR. As demonstrated in the pilot plant, better liquid product and hydrogen yields are attained at lower reactor pressure. The gross margin for the 50 psig case is almost $30,000/day higher than the 125 psig operation. The higher gross margin for low pressure operation offsets marginally higher EEC and catalyst requirements, that are attributable to the larger size of the low-pressure catalyst regenerator. Compression costs increase for the low pressure unit, but again, this cost is small compared to the value of higher reformate and hydrogen yields.

7.4.2 Choice of Naphtha Upgrading Route

FBR and split-naphtha upgrading routes are compared in Tables 7.2 and 7.3, respectively (refer to Figures 6.1 and 6.2). For each type of naphtha, the FBR flow scheme has an advantage. The split-naphtha approach has higher reformate and hydrogen yields, but the additional capital costs associated with this route are not economically justified with respect to FBR processing. If the reformate were given petrochemical value, the split-naphtha approach may have been justified. But for gasoline production, the simpler FBR route is a better alternative.

7.4.3 Naphtha Source

Naphtha sources are compared in Case 1 (Table 7.2) and Case 3 (Table 7.3). Upgrading Synthol naphtha is more economically attractive than upgrading straight-chain Arge naphtha. Both naphthas are lean by petroleum refining standards, but the presence of 15 wt-% aromatics in the Synthol as opposed to no aromatics in the Arge naphtha makes the difference. The unit reforming synthol naphtha can operate at higher LHSV than the Arge reforming unit, which has a beneficial effect on capital and operating costs. These benefits more than compensate for the yield loss associated with reforming branced paraffins relative to normal paraffins that was demonstrated in the pilot plant study.

7.5 SENSITIVITY CASES

The 50 psig Arge FBR Case (Table 7.1) and the Synthol FBR Case No. 3 (Table 7.3) were chosen as the basis for sensativity analyses.

7.5.1 Feedstock, Liquid Product Differential

The differential between feedstock cost and product value for the two cases was varied between $4.00/bbl and $6.50/bbl. Results are summarized in Table 7.4 and Figure 7.3. As expected, there is a strong relationship between value-added and economic return.

7.5.2 Hydrogen Co-Product Value

Hydrogen was valued between $275/MT, the approximate fuel value for 95 vol-% hydrogen (at $2.10/MM Btu), and its chemical value of $635/MT ($2.20/M SCF pure hydrogen). Results summarized in Table 7.5 and Figure 7.4 indicate that the IRR is attractive even if hydrogen is assigned fuel value.

TABLE 7.1

Economic Advantage of Low Pressure Reforming

	50 psig Case	125 psig Case
Naphtha Source	Arge	Arge
Naphtha Cut	FBR	FBR
Rx Pressure, psig	50	125
Feed Rate, BPSD	40,000	40,000
Feed Rate,cu.meters/day	6,359	6,359
Naphtha Sp.Gr.	0.7087	0.7087
Feed Rate, MT/day	4,507	4,507
Hydrogen Production Rate, MT/day	176	135
Fuel Gas Production Rate, MT/day	577	906
Reformate Production Rate, MT/day	3,754	3,466
Interest Charge = 10%		
Capitalization, MM $		
ISBL EEC	31.5	29.1
Offsites @40% of ISBL	12.6	11.6
Total EEC	44.1	40.7
1st yr Expenditure (20%)	10.7	9.9
2nd yr Expenditure (50%)	24.3	22.4
3rd yr Expenditure (30%)	13.2	12.2
Capitalized EEC	48.2	44.5
Royalties	5.0	5.0
Initial Catalyst Loading	5.3	4.7
Total Capital Requirement	58.4	54.1
Gross Margin, M $/day (a)	111.30	80.99
MM $/yr (355 op. days per year)	39.51	28.75
Utility Consumptions, negative value denotes export		
Electricity, kW	9,764	4,526
41.4 kg/sq cm, 400 C Steam, MT/hr	-32.9	-31.2
10.3 kg/sq cm, Sat. Steam, MT/hr	0.5	0.6
Boiler Feed Water, MT/hr	47.8	40.2
Condensate, MT/hr	-12.8	-7.6
Cooling Water, MT/hr	566.0	465.0
Fuel Fired, GJ/hr	381.1	338.2
Utility Unit Costs		
Electricity, $/kWh	0.040	0.040
41.4 kg/sq cm, 400 C Steam, $/MT	9.700	9.700
10.3 kg/sq cm, Sat. Steam, $/MT	8.160	8.160
Boiler Feed Water, $/MT	0.880	0.880
Condensate, $/MT	0.700	0.700
Cooling Water, $/MT	0.010	0.010
Fuel Fired, $/GJ	2.610	2.610

Note(a): Based on the Following Feedstock Cost and Product Values

	$/MT	$/bbl	$/M SCM	$/GJ
Hydrotreated Naphtha	170.42	19.20	---	---
Hydrogen	430.00	---	49.53	---
Fuel Gas	130.95	---	---	2.61
Reformate (100 RONC)	193.98	24.50	---	---

TABLE 7.1 - Continued

Economic Advantage of Low Pressure Reforming

	50 psig Case	125 psig Case
Naphtha Source	Arge	Arge
Naphtha Cut	FBR	FBR
Utility Operating Costs, $/day		
Electricity	9,373	4,345
41.4 kg/sq cm, 400 C Steam	(7,659)	(7,263)
10.3 kg/sq cm, Sat Steam	98	116
Boiler Feed Water	1,010	849
Condensate	(215)	(128)
Cooling Water	136	112
Fuel Fired	23,872	21,185
Total Utility Consumption, $/day	26,615	19,215
MM $/yr (355 op. days per year)	9.45	6.82
Labor Cost Basis		
Boardmen	1	1
Operators	2	2
Wage Rate, $/hr	15	15
Supervision, %	25	25
Fringe Benefits, %	35	35
Overhead. %	50	50
Total Labor Costs, MM $/yr	1.15	1.15
Maintenance, MM $/yr	0.63	0.58
Local Taxes and Insurance, MM $/yr	0.47	0.44
Operating Profit, MM $/yr		
Gross Margin	39.51	28.75
Interest on Working Capital	-1.25	-1.11
Catalyst and Chemicals	-1.60	-1.29
Utilities	-9.45	-6.82
Labor	-1.15	-1.15
Maintenance	-0.63	-0.58
Local Taxes & Insurance	-0.47	-0.44
Net Operating Profit, MM $/yr	24.97	17.37
Income Tax Rate = 33%		
Income Tax Liability, MM $/yr		
Net Operating Profit	24.97	17.37
Depreciation yrs 1-10	3.15	2.91
Taxible Income yrs 1-10	21.82	14.46
Income Tax Paid yrs 1-10	7.20	4.77
Taxible Income yrs 10+	24.97	17.37
Income Tax Paid yrs 10+	8.24	5.73
After-Tax Cash Flow, MM $/yr		
Years 1-10	17.77	12.60
Years 10+	16.73	11.64
Before-Tax IRR	42.7%	32.0%
After-Tax IRR	30.1%	22.7%

TABLE 7.2

Comparison of Arge Naphtha Upgrading Routes

	Case No. 1	Case No. 2
Process Scheme	FBR	Split
Process Units	1	2
Naphtha Source	Arge	Arge
Total Feed Rate, BPSD	40,000	40,000
Total Feed Rate,cu.meters day	6,359	6,359
FBR Naphtha Sp.Gr.	0.7087	0.7087
Total Feed Rate, MT/day	4,507	4,507
Hydrogen Production Rate, MT/day	176	205
Fuel Gas Production Rate, MT/day	577	403
Reformate Production Rate, MT/day	3,754	3,899
Interest Charge = 10%		
Capitalization, MM $		
ISBL EEC	31.5	40.7
Offsites @40% of ISBL	12.6	16.3
Total EEC	44.1	57.0
1st yr Expenditure (20%)	10.7	13.8
2nd yr Expenditure (50%)	24.3	31.3
3rd yr Expenditure (30%)	13.2	17.1
Capitalized EEC	48.2	62.2
Royalty Payment	5.0	5.0
Initial Catalyst Loading	5.3	6.3
Total Capital Requirement	58.4	73.6
Gross Margin, M $/day (a)	111.30	129.15
MM $/yr (355 op. days per year)	39.51	45.85
Utility Consumptions, negative value denotes export		
Electricity, kW	9,764	9,472
41.4 kg/sq cm, 400 C Steam, MT/hr	-32.9	-31.5
10.3 kg/sq cm, Sat Steam, MT/hr	0.5	0.5
Boiler Feed Water, MT/hr	47.8	47.9
Condensate, MT/hr	-12.8	-14.2
Cooling Water, MT/hr	566.0	559.0
Fuel Fired, GJ/hr	381.1	440.5
Utility Unit Costs		
Electricity, $/kWh	0.04	0.04
41.4 kg/sq cm, 400 C Steam, $/MT	9.70	9.70
10.3 kg/sq cm, Sat. Steam, $/MT	8.16	8.16
Boiler Feed Water, $/MT	0.88	0.88
Condensate, $/MT	0.70	0.70
Cooling Water, $/MT	0.01	0.01
Fuel Fired, $/GJ	2.61	2.61

Note(a): Based on the following feedstock cost and product values.

	$/MT	$/bbl	$/M SCM	$/GJ
Hydrotreated Naphtha	170.42	19.20	---	---
Hydrogen	430.00	---	49.53	---
Fuel Gas	130.95	---	---	2.61
Reformate (100 RONC)	193.98	24.50	---	---

TABLE 7.2 - Continued

Comparison of Arge Naphtha Upgrading Routes

	Case No. 1	Case No. 2
Process Scheme	FBR	Split
Utility Operating Costs, $/day		
Electricity	9,373	9,093
41.4 kg/sq cm, 400 C Steam	(7,659)	(7,333)
10.3 kg/sq cm, Sat. Steam	98	98
Boiler Feed Water	1,010	1,012
Condensate	(215)	(239)
Cooling Water	136	134
Fuel Fired	23,872	27,593
Total Utility Consumption, $/day	26,615	30,358
MM $/yr (355 op. days per year)	9.45	10.78
Labor Cost Basis		
Boardmen	1	1
Operators	2	2
Wage Rate, $/hr	15	15
Supervision, %	25	25
Fringe Benefits, %	35	35
Overhead, %	50	50
Total Labor Costs, MM $/yr	1.15	1.15
Maintenance, MM $/yr	0.63	0.81
Local Taxes and Insurance. MM $/yr	0.47	0.61
Operating Profit, MM $/yr		
Gross Margin	39.51	45.85
Interest on Working Capital	-1.25	-1.41
Catalyst and Chemicals	-1.60	-1.63
Utilities	-9.45	-10.78
Labor	-1.15	-1.15
Maintenance	-0.63	-0.81
Local Taxes & Insurance	-0.47	-0.61
Net Operating Profit, MM $/yr	24.97	29.46
Income Tax Rate = 33%		
Income Tax Liability. MM $/yr		
Net Operating Profit	24.97	29.46
Depreciation yrs 1-10	3.15	4.07
Taxible Income yrs 1-10	21.82	25.39
Income Tax Paid yrs 1-10	7.20	8.38
Taxible Income yrs 10+	24.97	29.46
Income Tax Paid yrs 10+	8.24	9.72
After-Tax Cash Flow, MM $/yr		
Years 1-10	17.77	21.08
Years 10+	16.73	19.74
Before-Tax IRR	42.7%	40.0%
After-Tax IRR	30.1%	28.3%

TABLE 7.3

Comparison of Synthol Naphtha Upgrading Routes

	Case No. 3	Case No. 4
Process Scheme	FBR	Split
Process Units	1	2
Naphtha Source	Synthol	Synthol
Total Feed Rate, BPSD	40,000	40,000
Total Feed Rate, cu.meters/day	6,359	6,359
FBR Naphtha Sp.Gr.	0.7191	0.7191
Total Feed Rate, MT/day	4,573	4,573
Hydrogen Production Rate, MT/day	128	197
Fuel Gas Production Rate, MT/day	636	370
Reformate Production Rate, MT/day	3,809	4,006
Interest Charge = 10%		
Capitalization, MM $		
ISBL EEC	28.6	41.9
Offsites @ 40% of ISBL	11.4	16.8
Total EEC	40.0	58.7
1st yr Expenditure (20%)	9.7	14.2
2nd yr Expenditure (50%)	22.0	32.3
3rd yr Expenditure (30%)	12.0	17.6
Capitalized EEC	43.7	64.1
Royalty Payment	5.0	5.0
Initial Catalyst Loading	3.9	6.1
Total Capital Requirement	52.6	75.1
Gross Margin, M $/day (a)	109.16	142.07
MM $/yr (355 op. days per year)	38.75	50.44
Utility Consumptions, negative value denotes export		
Electricity, kW	8,107	7,207
41.4 kg/sq cm, 400 C Steam, MT/hr	-25.5	-23.7
10.3 kg/sq cm, Sat. Steam, MT/hr	0.5	0.6
Boiler Feed Water, MT/hr	43.0	42.8
Condensate, MT/hr	-15.3	-17.0
Cooling Water, MT/hr	592.0	561.0
Fuel Fired, GJ/hr	347.9	407.5
Utility Unit Costs (Both Cases)		
Electricity, $/kWh	0.04	
41.4 kg/sq cm, 400 C Steam, $/MT	9.70	
10.3 kg/sq cm, Sat. Steam, $/MT	8.16	
Boiler Feed Water, $/MT	0.88	
Condensate, $/MT	0.70	
Cooling Water, $/MT	0.01	
Fuel Fired, $/GJ	2.61	

Note a: Based on the following feedstock cost and product values.

	$/MT	$/bbl	$/M SCM	$/GJ
Hydrotreated Naphtha	167.96	19.20	---	---
Hydrogen	430.00	---	49.53	---
Fuel Gas	130.95	---	---	2.61
Reformate (100 RONC)	193.98	24.50	---	---

TABLE 7.3 - Continued

Comparison of Synthol Naphtha Upgrading Routes

Process Scheme F-T Reactor Type	FBR Synthol	Split Synthol
Utility Operating Costs, $/day		
Electricity	7,783	6,919
41.4 kg/sq cm, 400 C Steam	(5,936)	(5,517)
10.3 kg/sq cm, Sat. Steam	98	118
Boiler Feed Water	908	904
Condensate	(257)	(286)
Cooling Water	142	135
Fuel Fired	21,792	25,526
Total Utility Consumption, $/day	24,530	27,798
MM $/yr (355 op. days per year)	8.71	9.87
Labor Cost Basis		
Boardmen	1	1
Operators	2	2
Wage Rate, $/hr	15	15
Supervision, %	25	25
Fringe Benefits, %	35	35
Overhead. %	50	50
Total Labor Costs, MM $/yr	1.15	1.15
Maintenance, MM $/yr	0.57	0.84
Local Taxes and Insurance, MM $/yr	0.43	0.63
Operating Profit, MM $/yr		
Gross Margin	38.75	50.44
Interest on Working Capital	-0.92	-1.30
Catalyst and Chemicals	-1.32	-1.47
Utilities	-8.71	-9.87
Labor	-1.15	-1.15
Maintenance	-0.57	-0.84
Local Taxes & Insurance	-0.43	-0.63
Net Operating Profit, MM $/yr	25.66	35.18
Income Tax Rate = 33%		
Income Tax Liability, MM $/yr		
Net Operating Profit	25.66	35.18
Depreciation yrs 1-10	2.86	4.19
Taxable income yrs 1-10	22.80	30.99
Income Tax Paid yrs 1-10	7.53	10.23
Taxable Income yrs 10+	25.66	35.18
Income Tax Paid yrs 10+	8.47	11.61
After-Tax Cash Flow, MM $/yr		
Years 1-10	18.14	24.95
Years 10+	17.20	23.57
Before-Tax IRR	48.8%	46.8%
After-Tax IRR	34.3%	33.0%

TABLE 7.4

Sensitivity Analysis of Feed and Liquid Product Differential

Feed to Product Differential $/bbl	FBR Synthol After-Tax IRR, %	FBR Arge After-Tax IRR, %
4.00	15.5	13.1
5.30	34.3	30.1
6.50	50.8	44.9

Basis: Data from 50 psig Case, Table 7.1, and Case No. 3, Table 7.3

TABLE 7.5

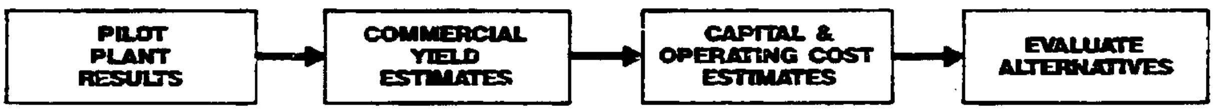
Sensitivity Analysis of Hydrogen Valuation

Hydrogen Value $/MT	FBR Synthol After-Tax IRR, %	FBR Arge After-Tax IRR, %
275	25.1	18.4
430	34.3	30.1
635	46.3	45.0

Basis: Data from 50 psig Case, Table 7.1, and Case No. 3, Table 7.3

FIGURE 7.1

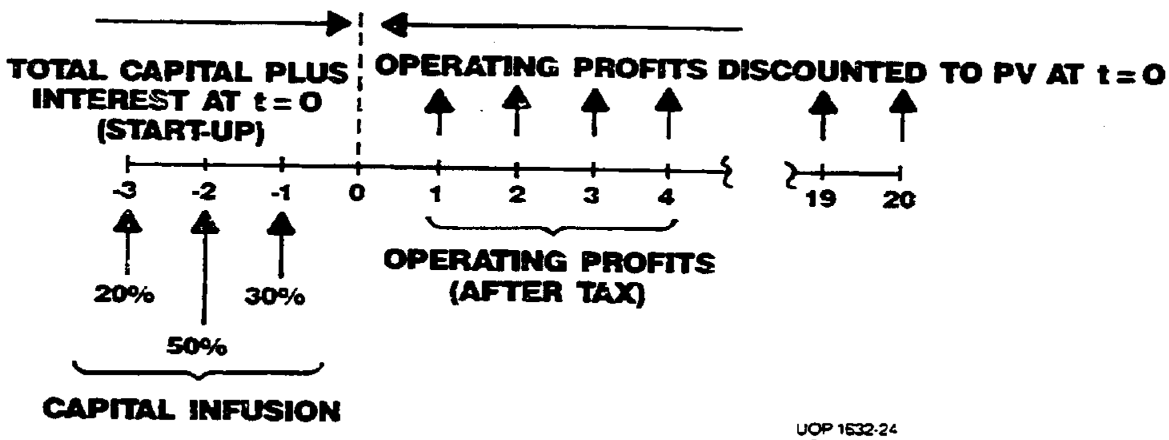
EVALUATION OF NEW TECHNOLOGY ALTERNATIVES



UOP 1632-22
UOP 1796-18

FIGURE 7.2

WHAT IS IRR?



UOP 1632-24
UOP 1796-19

FIGURE 7.3

VALUE-ADDED SENSITIVITY ANALYSIS

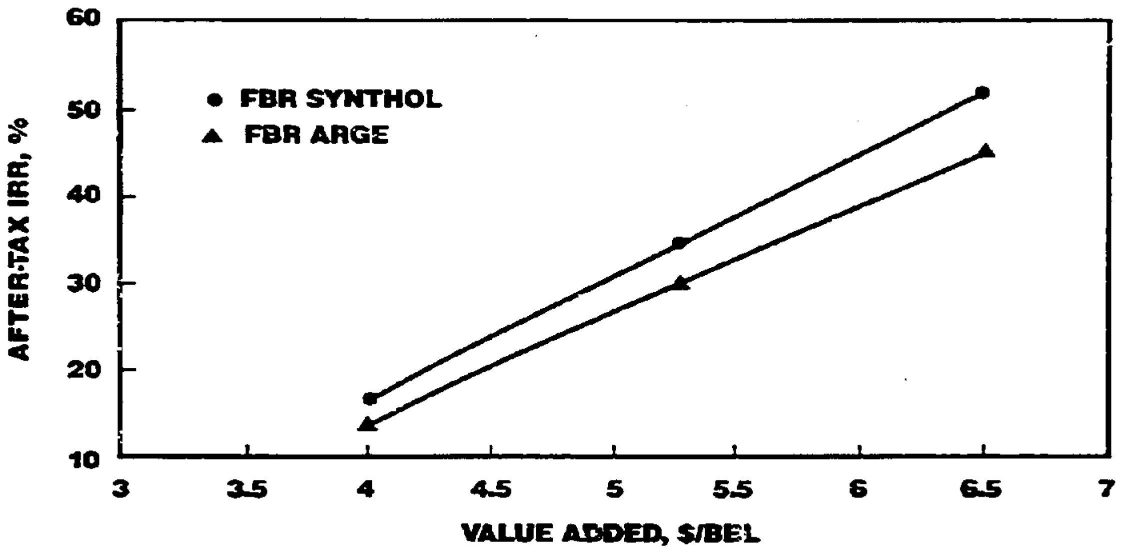


FIGURE 7.4

HYDROGEN-VALUE SENSITIVITY ANALYSIS