Appendix A

Methodology for Calculating the Required Price of Gas-Derived Products

A procedure has been developed to calculate the price of products produced from natural gas which is required to make investment in process facilities viable for the facility investor. The calculation procedure has been adapted from a GRI economic analysis calculation procedure, and much of the nomenclature has been retained in order that the procedure described here can be related to the GRI report.

The required price of gas-derived products is determined by summing the annual equivalents of the present worths of the following items, expressed in terms of a unit of product:

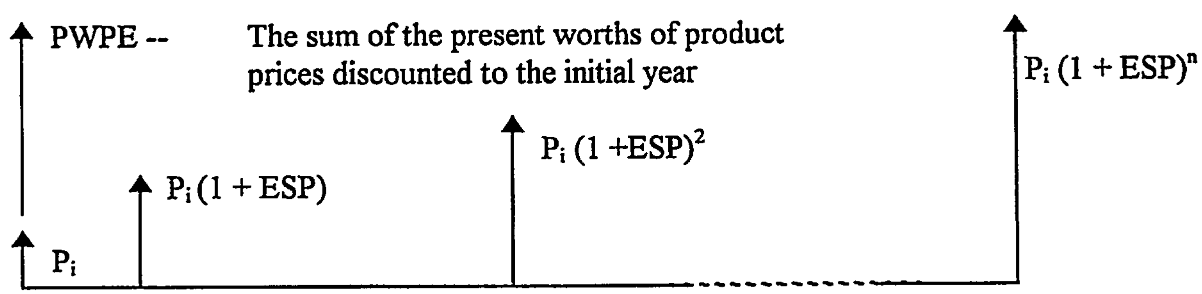
a. Cost of Process Facility, including Return (CPF)
b. Operating and Maintenance Cost (OMC)
c. Feedstock Cost (FC)
d. Cost of Working Capital (CWC)

The sum of these items is set equal to the annualized present worth of the revenue from the sale of a unit of product, as shown in the following equation:

CPF + OMC + FC + CWC = RPS (Revenue from Product Sales)

The revenue from sales is a function of the price of a specific gas-derived product and the price of the gas-derived product is assumed to grow over time. In the calculation routine, the gas-derived price is projected to grow at a constant rate and the estimate of price growth is entered as a percent of the inflation rate.

An example of the calculation procedure is presented for the methanol production case and is shown in Exhibit A-1. On the third page of the example, calculations are detailed for handling price growth and determining the impact on the required selling price of methanol products in the initial year. Price growth is input as PPGWR; in the example, it is 192% of the rate of inflation. The annual growth rate of product prices (ESP) is the inflation rate (INF) times the product price growth (PPGWR) divided by 100. The price in each year is diagrammed in the following figure:



For price increasing at a constant growth rate, a term TVPE replaces the discount rate in the usual present value formula. Thus:

$$PWPE = PW(YRS,TYPE) = \frac{(1+TVPE)^{YRS} - 1}{TVPE * (1+TVPE)^{YRS}}$$

and

$$TVPE = \frac{CDD - ESP}{1 + ESP}$$

where CDD is the current dollar discount rate. Similar formulas account for growth in operating cost, feed stock cost, and cost of working capital over time.

All of the costs and revenues are brought to their present worths in the initial year and then the annual equivalent of each cost is calculated by multiplying it by an annualization factor, ANBL. In the example, the annualizing factor is expressed in constant dollar terms. This was done because the set of calculations in the GRI reference document was done in constant dollars and because many of the forecasts of crude oil and gas price growth are given in constant dollar terms. The answer for the price of gas-derived products in the initial year will be the same regardless of whether you work in constant or current dollars. The ANBL terms appear in all the individual elements. It is important to note that working in constant dollars does yield a value of CCR, the capital charge factor, that is lower than expected by those who are attuned to analyzing in a current dollar framework.

Data input to run the calculation program appears on pages 1 and 3 of the example output. On Page 1 of Exhibit A-1, results of the cost estimating work is input in the upper box. The calculation of total plant cost and variable operating and maintenance cost follows the procedure outlined in the EPRI "TAG". The percent cost factors on Pages 1 and 2 of Exhibit A-1 can be changed at the users discretion. The result of the calculations on page 1 is the total plant investment (TPI) for the gas upgrading plant. On Page 2, the variable operating and maintenance cost (VOM), the feedstock cost (FC), and the working capital cost (WC) for the initial year of operation are calculated.

On Page 3 of the sample calculation, the economic analysis of the project is performed to calculate the price of gas that is required to provide the return on investment commensurate with the inputs on discount rate, life, and financing assumptions. Definitions for the variables in the formulas in the example calculation are given in Exhibit A-2. METC has been provided with a copy of the calculation routine used to produce the example calculation. This routine is a spreadsheet file that will work with either Lotus 1-2-3 (file extension .WK1) or Quattro Pro (file extension .WQ1).

Exhibit A-1

CASE: MeOH
COST BASIS: DEC,1993

Feed Stream: Natural Gas

Page 1 -- Calculate Total Plant Investment Cost

INPUTS FROM COST ESTIMATION

Design Cap(MMgal/yr MeOH)	DC	607
Service Factor	SF	0.9132
Process Field Cost(MM$)	PFC	210.5
Operators/Shift	OPS	35
Cat & Chemicals(M$/Yr)	CAC	7.2
Makeup Water(MGal/min)	MUW	0
Feed Gas($/MMBTU)	FGS	2.43
Feed Gas(MMBTU/Hr)	FG	6258

TOTAL PLANT COST	COST FACTOR%		COST,MM$
PROCESS			
Field Cost Direct and Indirect		PFC	210.5
Sales Tax %	0		0.0
			======
Basic Facility Construction Investment		BFCI	210.5
Project Contingency % of BFCI	15	PC	31.6
			======
			242.1
Home Office % of BFCI+PC	6		14.5
Engineering % of BFCI+PC	6		14.5
			======
Total Process Facilities Construction Invstment		TPFCI	271.1
OFFSITES/UTILITIES: DIRECT AND INDIRECT			
Field Cost, Direct and Indirect			
Util & Gen Facilities % of Process BFCI	44.9		94.5
Project Contingency % of Offsites	15		14.2
			======
BFCI Offsites + Proj. Contingency			108.7
Home Office % of Offsites BFCI+PC	6		6.5
Engineering % of Offsites BFCI+PC	6		6.5
			======
Total Offsites/Utilities Construction Investment		TOFCI	121.7
Total Facilities Constrctn Invst(TPFCI+TOFCI)		TFCI	392.9
TOTAL PLANT INVESTMENT(TPI)			
Total Facilities Constrctn Invst			392.9
Initial Fills % of TFCI	0.8		3.1
Startup % of Ann Opr Cost(AOC)	20		33.9
Prepaid Royalties % of TFCI	0.5		2.0
			======
Total Plant Investment		TPI	[illegible]

LIQUID PHASE METHANOL

Feed Stream: Natural Gas

CASE: MeOH

COST BASIS: DEC,1993	DATA INPUTS Estimate	% Fact.		COSTS MM$/YR
TOTAL MAINTENANCE COST				
Facilities: % of TFCI		4.1	TMC	16.1

Page 2 - Calculate Operating & Maintenance Cost

VARIABLE OPR & MAIN COST(MM$/YR)	Estimate	% Fact.		COSTS MM$/YR
DIRECT LABOR COST				
Operators Per Shift	35			
Annual Dir Lab @ $/Hr	18.08			5.1
Maintenance Lab(% TMC)		40		6.4
				======
Total Direct Labor			TDL	11.5
Labor Overheads				
Supervision % of TDL		25		2.9
Benefits % of TDL		25		2.9
Gen & Clerical % of TDL		45		5.2
Corporate OH % of TDL		30		3.5
Supplies % of TDL		5		0.6
				======
Total Labor Overheads				15.0
Catalyst & Chemicals MM$				7.2
Utilities				
Imported Power, Gas, Steam	0			-13.0
Makeup Water MGal/Min(MUW)	0			
Water Cost $/MGal	0.0125			0.0
Maintenance Materials % of TMC		60		9.7
Local Taxes & Ins % of TFCI		1.5		5.9
				======
Total Other O&M				9.8
Var Opr & Main(DL+Lab OH+Oth O&M)			VOM	36.2
Feed Nat Gas ($/MMBTU)	2.43			
Feed Nat Gas MMBTU/Hr	6258		FC	133.2
				======
Ann Opr Cost YR 1(VOM+FC)			AOC	169.4
Working Cap(Consm & Parts)% of TFCI		1.4		5.5
Working Cap(Acct Rec)1 Mon of AOC				14.1
				======

Exhibit A-1 (Continued)

CASE: MeOH — Feed Stream: Natural Gas

CONSTANT $ DISC	KDD	0.09	UNIT REVENUES AND COSTS FOR FIRST YEAR			
INFLATION	INF	0.0301	BASE YR PROD REV	BPR		
FRAC CAP FROM EQ	FCE	0.8	SPC CAP COST(TPI/DC*SF)	SPI	0.779	$/gal
FRAC CAP FROM DBT	FCD	0.2	O&M COST(Base Yr)	OMC	0.065	$/gal
RETURN ON EQUITY	ROE	0.142	FEED COST(YR 1)	FDC	0.240	$/gal
RETURN ON DEBT	ROD	0.09	WORKING CAPITAL(YR 1)	UWC	0.035	$/gal
BOOK LIFE YRS	YRS	20	PD PRICE GW(% INF)	PPGWR	192	
TAX LIFE	TYR	10	O&M COST GW(% INF)	OMGWR	100	
TAX RATE	FIT	0.4	FEED COST GW(%INF)	FCGWR	236	
CONSTRUCTN PERIOD	CYR	3	WORK CAP GW(% INF)	WCGWR	100	
ALW FUND DUR CONST	AFDUC	0.11	Calculate			
ESCAL RATE CONSCT	ESC	0.0301	ESCAL RATE PRODUCT	ESP		
Calculate			ESCAL RATE FUEL	ESF		
WT AVG AFT TAX COC	ATCOC		ESCAL RATE O&M	ESO		
CURRENT $ DISC	CDD	0.122809				

ATCOC = +ROE*FCE+(1-FIT)*(ROD*FCD)	ATCOC	0.124
CDD = +(1+INF)*(1+KDD)-1	CDD	0.123
PW(YRS,CDD) = ((1+CDD)^YRS-1)/(CDD*(1+CDD)^YRS)	PWBL	7.340
Ann(YRS,KDD) = +(KDD*(1+KDD)^YRS)/((1+KDD)^YRS-1)	ANBL	0.110
ESP = +INF*(PPGWR/100)	ESP	0.058
TVPE = +(CDD-ESP)/(1+ESP)	TVPE	0.061
PW(YRS,TVPE) = ((1+TVPE)^YRS-1)/(TVPE*(1+TVPE)^YRS)	PWPE	11.335
ESO = +INF*(OMGWR/100)	ESO	0.030
TVOME = +(CDD-ES0)/(1+ESO)	TVOME	0.090
PW(YRS,TVOME) = ((1+TVOME)^YRS-1)/(TVOME*(1+TVOME)^YRS)	PWOME	9.129
ESF = +INF*(FCGWR/100)	ESF	0.071
TVFCE = +(CDD-ESF)/(1+ESF)	TVFCE	0.048
PW(YRS,TVFCE) = ((1+TVFCE)^YRS-1)/(TVFCE*(1+TVFCE)^YRS)	PWFDE	12.640
ESW = +INF*(WCGWR/100)	ESW	0.030
TVWCE = +(CDD-ESW)/(1+ESW)	TVWCE	0.090
PW(YRS,TVWCE) = ((1+TVWCE)^YRS-1)/(TVWCE*(1+TVWCE)^YRS)	PWWCE	9.129
PW(TYR,CDD) = ((1+CDD)^TYR-1)/(CDD*(1+CDD)^TYR)	PWTL	5.586
EEL3 = +2*(TYR-PWTL)/(TYR*(TYR+1)*CDD)	EEL3	0.654
EEL1 = +(1+AFDUC)^(CYR/3)	EEL1	1.110
EEL2 = +FIT*(FCE+FCD*(1+AFDUC)^(CYR/3))	EEL2	0.409
EEL4 = +((PWBL/YRS)*(1-(ATCOC/CDD))+(ATCOC/CDD)*EEL3)	EEL4	0.657

CCR = +ANBL/(1-FIT)*(1/(1+ESC))^(CYR/3)*EEL1*((PWBL/YRS)*(1-ATCOC/CDD)+ATCOC/CDD)-EEL2*EEL4)

	CCR	0.151

SPI*CCR = (BPR*ANBL*PWPE)-(OMC*ANBL*PWOME)-(FDC*ANBL*PWFDE)-(UWC*ANBL*PWWCE)

Let TOPC = +[(OMC*ANBL*PWOME)+(FDC*ANBL*PWFDE)+(UWC*ANBL*PWWCE)]	TOPC	0.434
	SPI*CCR	0.117
BPR = +((SPI*CCR)+TOPC)/(ANBL*PWPE)	BPR	0.444

PRICE OF METHANOL PRODUCT IN INITIAL YEAR($/Gallon) = 0.444

Exhibit A-2

DEFINITION OF TERMS

AFDUC	Allowance for Funds During Construction represents interest costs
Ann (t,d)	Annualized value of a present worth over t years at a discount rate of d (equal to 1/PW(t,d))
ATCOC	Weighted average After Tax Cost of Capital, based on funding from equity and debt
BPR	Base Product Revenue is the revenue from the sale of a unit of product in the first year of operation, i.e., the product price
CCR	Capital Charge Rate, which related the unit capital investment to the annualized value of operating costs and revenues (in this case, the CCR is on a constant $ basis)
CDD	Current Dollar Discount factor
CYR	Construction period in YeaRs during which investment $'s are expended
ESO	Escalation factor for Operating and maintenance cost
ESP	Annual Escalation factor for Product price
FCD	Fraction of investment Capital from Debt sources
FCE	Fraction of investment Capital from Equity sources
FCGWR	Constant annual Feed Cost GroWth Rate stated at % of inflation rate
FCD	Feed Cost in initial year, treated separated from other operating cost to allow for differences in cost escalation rates
INF	General rate of inflation

Exhibit A-2 (Continued)

DEFINITION OF TERMS

KDD	Konstant Dollar Discount rate
PPGWR	Constant annual Product Price Growth Rate stated as % of inflation rate
PW(t,d)	Uniform series Present Worth factor for t years at discount rate d
SPI	Specific Plant Investment is the cost of investment per unit of production capacity. It is the Total Plant Investment divided by the Design Capacity times the Stream Factor
TOPC	Total Operating Cost is the sum of the annualized present worths of the operating and maintenance costs, the feed cost and the cost of working capital
TVOME	Time Value of Operating and Maintenance cost Price Escalation relative to the discount factor CDD, when the O&M cost is increasing at a constant rate of growth then TVOME replaced the *d* discount in the PW(t,d) relationship
TYR	Tax life in years over which investment is depreciated
YRS	Operating life of the investment in years

Exhibit A-3. Summary of Economics for Conversion of Natural Gas to Transportation Fuels

Type of Process	Natural Gas to Methanol LPMEOH	Natural Gas to Gasoline and Diesel Fischer-Tropsch	Natural Gas to Gasoline and Diesel - Fischer-Tropsch Low Feed Cost	Natural Gas to Gasoline by Oxidative Coupling	Natural Gas to C1 - C6 Alcohol IFP Process	Methanol and Butane to MTBE UOP Process
Design Product Capacity, BPSD	39572	14500	14500	14500	15060	12500
Natural Gas Feed Rate, 10^6 Btu/Hr	6852	5390	5390	5412	3850	-
Methanol Feed Rate, BPSD	-	-	-	-	-	4250
Butane Feed Rate, BPSD	-	-	-	-	-	12011
Operators per Shift	35	22	22	22	11	10
Process Field Cost, 10^6\$	271.1	437.1	437.1	570.7	392.0	108.6
Offsite/Utility Field Cost, 10^6\$	121.7	311.2-	311.2	289.9	196.0	32.5
Initial Owner Cost, 10^6\$	39.0	41.7	29.6	49.2	31.7	22.9
Total Plant Investment, 10^6\$	431.8	790.1	777.9	909.8	619.8	163.9
Total Direct Labor, 10^6\$/Yr	11.5	12.1	12.1	16.6	6.3	4.1
Total Labor Overheads, 10^6\$/Yr	15.0	15.8	15.8	21.5	8.2	5.3
Total Other O&M, 10^6\$/Yr	9.8	28.8	28.8	48.2	31.2	20.0
Total Var Opr &Main, 10^6\$/Yr	36.2	56.7	56.7	86.3	45.7	29.3
Feedstock Cost, 10^6\$/Yr	133.2	103.3	42.5	103.7	74.8	87.6
Ann. Operating Cost, 10^6\$/Yr	169.4	160.0	99.2	190.0	120.5	101.3**
Working Capital, 10^6\$/Yr	19.6	23.8	18.7	27.9	18.3	10.4
Capital Charge, \$/Barrel	4.91	24.53	24.15	28.25	18.26	5.87
O&M Cost (Year 1), \$/Barrel	2.73	11.90	11.90	18.11	9.10	7.13
Feed Cost (Year 1), \$/Barrel	10.08	21.68	8.92	21.77	14.91	21.33
Working Capital (Year 1), \$/Barrel	1.47	5.00	3.93	5.85	3.64	2.54
Product Price, \$/Barrel*	18.65	57.46	43.46	71.12	50.37	36.06
Product Price, \$/Gallon*	0.444	1.37	1.03	1.69	1.20	0.86

*Basis: 14.2% DCF ROE **Includes 15.5 x 10^6 \$/Yr Byproduct Value

Exhibit A-4. Summary of Economics for Conversion of Natural Gas to Transportation Fuels

Type of Process	Natural Gas to Gasoline by Oxyhydrochlorination	Production of Liquefied Natural Gas (LNG)	Production of Compressed Natural Gas (CNG)
Design Product Capacity (Stream)	14500 BPSD	168 x 10^6 gal/Yr. LNG	108274 x 10^6 Btu/Yr. CNG
Natural Gas Feed Rate, 10^6 Btu/Hr (Cal)	4466	1717	9.44
Operators per Shift	22	2.2	0.25
Process Field Cost, 10^6\$	522.5	63.1	0.246
Offsite/Utility Field Cost, 10^6\$	379.5	0	0
Initial Owner Cost, 10^6\$	54.4	13.9	0.087
Total Plant Investment, 10^6\$	956.4	77.0	0.333
Total Direct Labor, 10^6\$/Yr	21.2.	0.7	0.032
Total Labor Overheads, 10^6\$/Yr	27.5	0.9	0.041
Total Other O&M, 10^6\$/Yr	69.9	1.5	0.006
Total Var Opr &Main, 10^6\$/Yr	118.6	3.2	0.079
Feedstock Cost, 10^6\$/Yr	95.1	62.3	0.342
Ann. Operating Cost, 10^6\$/Yr	213.6	65.4	0.421
Working Capital, 10^6\$/Yr	30.4	6.3	0.039
Capital Charge	29.7 \$/Barrel	0.072 \$/gal LNG	0.61 \$/MMBTU
O&M Cost (Year 1)	24.9 \$/Barrel	0.020 \$/gal LNG	0.95 \$/MMBTU
Feed Cost (Year 1)	20.0 \$/Barrel	0.387 \$/gal LNG	4.14 \$/MMBTU
Working Capital (Year 1)	6.4 \$/Barrel	0.034 \$/gal LNG	0.47 \$/MMBTU
Product Price*	76.5 \$/Barrel	0.537 \$/gal LNG	6.25 \$/MMBTU
Product Price*	1.82 \$/Gallon	0.85 \$/geg	0.73 \$/geg
Natural Gas Price, \$/10^6 Btu	2.43	4.14	4.14
*Basis: 14.2% DCF ROE geg = gasoline equivalent gallon			

Exhibit A-5. Summary of Economics for Conversion of Natural Gas to Chemicals

Type of Process	Natural Gas to Methanol - High Quality Natural Gas	Natural Gas to Methanol - Low Quality Natural Gas	Natural Gas to Ammonia - High Quality Natural Gas	Natural Gas to Ammonia - Low Quality Natural Gas
Design Product Capacity (Stream)	39572 BPSD	39572 BPSD	420 MST/Yr. NH_3	420 MST/Yr. NH_3
Natural Gas Feed Rate, 10^6 Btu/Hr (cal)	6258	6566	885	885
Operators per Shift	35	35	40	40
Process Field Cost, 10^6\$	271.1	285.0	111.7	116.3
Offsite/Utility Field Cost, 10^6\$	121.7	125.7	20.2	21.1
Initial Qwner Cost, 10^6\$	39.0	39.0	11.6	11.6
Total Plant Investment, 10^6\$	431.9	449.7	143.4	148.9
Total Direct Labor, 10^6\$/Yr	11.5	11.8	6.4	6.8
Total Labor Overheads, 10^6\$/Yr	15.0	15.3	8.3	8.8
Total Other O&M, 10^6\$/Yr	9.8	10.5	15.7	15.8
Total Var Opr &Main, 10^6\$/Yr	36.2	37.6	30.4	31.4
Feedstock Cost, 10^6\$/Yr	133.2	130.3	18.8	17.4
Ann. Operating Cost, 10^6\$/Yr	169.4	167.9	49.2	48.8
Working Capital, 10^6\$/Yr	19.6	19.7	6.0	6.0
Capital Charge	4.91 \$/Bbl	5.12 \$/Bbl	57 \$/ST	59 \$/ST
O&M Cost (Year 1)	2.73 \$/Bbl	2.86 \$/Bbl	80 \$/ST	83 \$/ST
Feed Cost (Year 1)	10.08 \$/Bbl	9.87 \$/Bbl	50 \$/ST	46 \$/ST
Working Capital (Year 1)	1.47 \$/Bbl	1.51 \$/Bbl	16 \$/ST	16 \$/ST
Product Price*	18.65 \$/Bbl MeOH	18.65 \$/Bbl MeOH	240 \$/ST NH_3	240 \$/ST NH_3
Product Price*	0.444 \$/gal MeOH	0.444 \$/gal MeOH		
Natural Gas Price, \$/10^6 Btu	2.43	2.27	2.43	2.24
*Basis: 14.2% DCF ROE				

Exhibit A-6. Summary of Economics for Conversion of Natural Gas to Power, Nitrogen Rejection and Production of Methyl Chloride

Type of Process	Natural Gas to Power - High Quality Natural Gas	Natural Gas to Power - Low Quality Natural Gas	Rejection of Nitrogen from Low Quality Natural Gas	Natural Gas to Methyl Chloride by Oxyhydrochlorination
Design Product Capacity (Stream)	426 MW	426 MW	5932 x 10^6 Btu/Yr.	8112 Tons/Day
Natural Gas Feed Rate, 10^6 Btu/Hr (Cal)	2627	2641	663	4466
Operator per Shift	6.25	6.25	2	17
Process Field Cost, 10^6\$	180.1	192.7	6.811	402.4
Offsite/Utility Field Cost, 10^6\$	25.8	27.8	0.279	292.1
Initial Owner Cost, 10^6\$	16.9	17.0	2.246	46.3
Total Plant Investment, 10^6\$	222.9	237.4	9.336	740.8
Total Direct Labor, 10^6\$/Yr	1.5	1.6	0.418	16.3
Total Labor Overheads, 10^6\$/Yr	2.0	2.0	0.543	21.2
Total Other O&M, 10^6\$/Yr	12.3	13.1	0.818	53.8
Total Var Opr &Main, 10^6\$/Yr	15.7	16.7	1.778	91.3
Feedstock Cost, 10^6\$/Yr	55.9	53.7	8.991	95.1
Ann. Operating Cost, 10^6\$/Yr	71.7	70.4	10.769	186.4
Working Capital, 10^6\$/Yr	8.9	9.0	0.997	25.3
Capital Charge	0.011 \$/kWh	0.012 \$/kWh	0.242 \$/MMBTU	41 \$/Ton
O&M Cost (Year 1)	0.005 \$/kWh	0.006 \$/kWh	0.312 \$/MMBTU	34 \$/Ton
Feed Cost (Year 1)	0.019 \$/kWh	0.018 \$/kWh	1.579 \$/MMBTU	36 \$/Ton
Working Capital (Year 1)	0.003 \$/kWh	0.003 \$/kWh	0.175 \$/MMBTU	9 \$/Ton
Product Price*	0.037 \$/kWh	0.037 \$/kWh	2.431 \$/MMBTU	116 \$/Ton
Natural Gas Price, \$/10^6 Btu	2.43	2.32	1.71	2.43
*Basis: 14.2% DCF ROE				

Exhibit A-7. Summary of Economics of Sensitivity to Gas Price Growth Rate and Plant Size for Fischer-Tropsch Process with Slurry Reactor

Principal Variable	Base Case with Slurry Reactor	% Growth Rate for Natural Gas			Four Times Base Case Plant Size
		0.6	1.6	3.9	
Design Product Capacity, BPSD	14500	14500	14500	14500	58000
Natural Gas Feed Rate, 10^6 Btu/Hr	5201	5201	5201	5201	20804
Operator per Shift	22	22	22	22	47
Process Field Cost, 10^6\$	381.6	381.6	381.6	381.6	1367.9
Offsite/Utility Field Cost, 10^6\$	304.9	304.9	304.9	304.9	504.8
Initial Owner Cost, 10^6\$	40.1	40.1	40.1	40.1	66.6
Total Plant Investment, 10^6\$	726.7	726.7	726.7	726.7	1939.3
Total Direct Labor, 10^6\$/Yr	11.4	11.4	11.4	11.4	24.5
Total Labor Overheads, 10^6\$/Yr	14.8	14.8	14.8	14.8	31.8
Total Other O&M, 10^6\$/Yr	30.4	30.4	30.4	30.4	86.0
Total Var Opr &Main, 10^6\$/Yr	56.6	56.6	56.6	56.6	142.2
Feedstock Cost, 10^6\$/Yr	99.6	99.6	99.6	99.6	398.6
Ann. Operating Cost, 10^6\$/Yr	156.2	156.2	156.2	156.2	540.8
Working Capital, 10^6\$/Yr	22.6	22.6	22.6	22.6	71.3
Capital Charge \$/Barrel	22.56	22.56	22.56	22.56	15.05
O&M Cost (Year 1), \$/Barrel	11.88	11.88	11.88	11.88	7.47
Feed Cost (Year 1), \$/Barrel	20.92	20.92	20.92	20.92	20.92
Working Capital (Year 1), \$/Barrel	4.75	4.75	4.75	4.75	3.74
Product Price, \$/Barrel	56.84	52.76	54.04	58.87	45.67
\$/Gallon	1.35	1.26	1.29	1.40	1.09
Natural Gas Price, \$/10^6 Btu	2.43	2.43	2.43	2.43	2.43
Annual % Growth Rate for Natural Gas Price	3.1	0.6	1.6	3.9	3.1

Exhibit A-8. Summary of Economics of Sensitivity to Location and Gas Price for Fischer-Tropsch Process with Slurry Reactor

Principal Variable	Barge Mounted Plant	Location - Alaska North Slope	Natural Gas Price - $0.50/10₆ Btu	Natural Gas Price - $0.00/10₆ Btu
Design Product Capacity, BPSD	14500	14500	14500	14500
Natural Gas Feed Rate, 10^6 Btu/Hr	5201	5201	5201	5201
Operator per Shift	22	22	22	22
Process Field Cost, $10^6$$	598.3	644.9	381.6	386.1
Offsite/Utility Field Cost, $10^6$$	478.0	515.3	304.9	304.9
Infrastructure, $10^6$$	636.3	0	0	0
Initial Owner Cost, $10^6$$	27.5	37.9	24.3	20.2
Total Plant Investment, 10^6 $	1740.1	1198.0	710.9	706.8
Total Direct Labor, $10^6$$/Yr	18.4	19.4	11.4	11.4
Total Labor Overheads, $10^6$$/Yr	24.0	25.3	14.8	14.8
Total Other O&M, $10^6$$/Yr	44.0	48.7	30.4	30.4
Total Var Opr &Main, $10^6$$/Yr	86.4	93.4	56.6	56.6
Feedstock Cost, $10^6$$/Yr	20.5	20.5	20.5	0
Ann. Operating Cost, $10^6$$/Yr	106.9	113.9	77.1	56.6
Working Capital, $10^6$$/Yr	24.0	25.7	16.0	14.3
Capital Charge, $/Barrel	54.10	37.19	22.07	21.94
O&M Cost (Year 1), $/Barrel	18.13	19.60	11.88	11.88
Feed Cost (Year 1), $/Barrel	4.30	4.30	4.30	0
Working Capital (Year 1), $/Barrel	5.03	5.40	3.37	3.01
Product Price $/Barrel	71.88	57.44	35.95	31.81
$/Gallon	1.71	1.37	0.86	0.76
Natural Gas Price, $/10^6$ Btu	0.50	0.50	0.50	0
Annual % Growth Rate for Natural Gas Price	3.9	0	0	0