EIA Model Documentation

PETROLEUM MARKET MODEL
OF THE
NATIONAL ENERGY MODELING SYSTEM

Part 2 - Appendices B thru J

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APPENDIX B

Mathematical Description of Model

APPENDIX B. Mathematical Description of Model

Each refiner is trying to minimize the cost of meeting demands. Therefore, the market moves toward lower-cost refiners who have access to crude oil and markets. A key premise is that the selection of crude oils, refinery process utilization, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products.

In order to generate refined product prices, the PMM contains a static linear programming (LP) model of the U.S. petroleum refining and marketing system that meets demand for refined products while minimizing costs. The PMM, like the other NEMS models, is written in FORTRAN90. The software includes the Optimization Modeling Library (OML), a set of FORTRAN callable subroutines. The LP portion of the PMM is a complete problem matrix prepared prior to NEMS processing. The LP remains in fast memory throughout the NEMS run, thereby avoiding many disk I/O operations.

It is necessary to view the PMM in the context of the NEMS program to understand its function. For each cycle, the main NEMS model calls the demand models to calculate energy demands. Each supply model is then called to calculate energy prices. When the prices and demands converge to within the specified tolerance, the NEMS iteration is complete and the next yearly NEMS cycle begins. If the computed prices have not converged, new demand quantities are computed, passed to the supply models, and the cycle is repeated. In the case of the PMM, a supply model, the refined product prices are obtained from the marginal prices of an optimal solution to the PMM LP, with transportation costs and taxes added. These product prices are sent to the NEMS demand models. The LP matrix is updated with the new demands for refined products and the cycle continues until convergence is reached. The demand level modifications to the PMM LP and the re-optimization of the LP matrix, which remains in core memory, are accomplished by executing FORTRAN callable subroutines.

For *AEO2006* the original generation of the PMM matrix is performed using OML[1] and FORTRAN. OML (Optimization Modeling Library) is a library of FORTRAN callable subroutines for data table manipulation, matrix generation, and solution retrieval programs for report writing. The matrix is solved with the optimizer, C-WHIZ.[2]

B.1 Mathematical Formulation

The table of column activity definitions and row constraints defined in the PMM matrix incorporate certain premises which are described in Appendix A. The general structure of the matrix is shown in Table B1.

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[1]Ketron Management Science, Inc., *Optimization Modeling Library, OML User Manual*, (November 1994).

[2]Ketron Management Science, Inc., *C-WHIZ Linear Programming Optimizer, User Manual*, (July 1994).

Table B1. PMM Linear Program Structure

PMM Linear Program Overview

	Crude Trans.	Purchases Crude Oil, Other Inputs	Crude Distillation	Other Process Unit Operations	Capacity Expansion	Stream Transfers	Blending	Product Sales	Product Trans.	Row Type	RHS
Objective	-ct	-c	-o	-o	-i			+p	-pt	NC	Max
Crude Oil Balance	+1 +1 -1	+1 +1 +1	-1 -1							GE	0
Intermediate Stream Balance			+y +y	-1 -1 +y +y		-1 -1 +1 +1	-1 -1			GE	0
Utilities		+1	-u	-u +1						GE	0
Policy Constraints				+z -z				+z -z		GE LE	0
Environmental Constraints			+q	+q						GE LE	E
Unit Capacities			+1	+1	-1					LE	K
Quality Specifications							+q +q -Q			GE LE	0
Product Sales							-1	-1	-1 +1 +1 -1	GE	0
Pipeline/Marine Capacities	+1 +1								+1 +1	LE	C
Bounds	Up/Lo/Fix	Up/Lo/Fix						Up/Lo/Fix			

Legend:
c = crude cost
p = price
Q = product specifications
y = yield
z = policy ratio
u = utility consumption
q = stream quality
K = unit capacity
ct = crude transportation cost
C = pipeline/marine capacity
E = environmental quality limit
o = operating cost
pt = product transportation cost
i = investment cost

B.2 Matrix Indices

Several indices are used in the column and row definitions presented below. The definition of these indices is shown in Table B2.

Table B2. Index Definitions

<u>Index Symbol</u>	<u>Description</u>
(a)	Alcohol and renewable fuel (ETH, ETC, BIN, BIM)
(b)	Domestic crude oil production region (OGSM regions A,1-6)
(c)	Crude oil type
(col)	Coal type
(d)	Marketing region (demand regions 1-9)
(e)	Emissions source (policy)
(emis)	Emissions type (NOx, CO1, CO2, CAR, SOX, VOC)
(f)	Fuel type consumed at US refineries
(g)	Dry gas (CC1)
(h)	Product recipe
(i)	Intermediate stream
(l)	Utility type (kwh, ngs, stm)
(m)	Processing mode or shipping mode
(p)	Refined product
(pc)	Shipping class
(q)	Pricing level (step on curve)
(r)	Refinery region
(s)	Refinery stream
(u)	Processing unit type
(v)	Crude oil source (foreign(F), domestic(D), Alaska(A))
(y)	Product specification quality

B.3 Column Definitions

Table B3. Column Definitions

Column Notation	Description
$B_{a,d,q}$	Volume of alcohol or renewable fuel (a) purchased in demand region (d) at price level (q). At present, this column exists for ethanol and biodiesel.
$D_{p,d}$	Sales volume of product (p) in demand region (d).
$E_{u,r}$	Stream day capacity added during this simulated period for processing unit type (u) in refinery region (r).
$G_{i,p,r}$	Volume of intermediate stream (i) blended into spec blended product (p) at refinery region (r).
$H_{p,h,r}$	Volume of product (p) produced in refinery region (r) using recipe (h).
$H_{p,h,d}$, $H_{RFN,h,d}$	Volume of product (p) made by recipe (h) in demand region (d) by splash blending; volume of intermediate stream (i) from gas plant to refinery (RFN) in region (r)
$H_{p,i,r}$	Volume of product (p) from gas plant stream (i) in refinery region (r).
$H_{g,i,r}$	Volume of natural gas liquids stream (i) left in dry gas (g) at gas plant.
$HKWHMCH_r$	Electricity usage at merchant plant in refinery region (r).
$HMP_{FR,TO,i,r}$	Merchant plant stream transfers from plant (FR) to plant (TO): Volume of GTL liquid stream (i) transferred from Alaska (merchant plant) to refinery region (r); volume of CTL liq stream (i) transferred from facility to refinery region (r); volume of misc. stream (i) from merchant plant to refinery region (r); volume of misc. stream (i) from refinery to merchant plant in region (r) ; volume of misc. stream (i) from gas plant to merchant plant in region (r); volume of misc. stream (i) from merchant plant to gas plant in region (r).
$Iz_{p,d}$	Volume of distress import of product (p) into demand region (d) where d = 2,3,7,8,9.
$I_{p,r,q}$	Volume of refined product (p) imported into refinery region (r) at price level (q).

Column Notation	Description
$K_{u,r}$	Base processing capacity in processing unit (u) at refinery region (r) in Mbbl/cd. This column is upper bounded.
$L_{u,r}$	Cumulative stream day capacity added for processing unit (u) at refinery region (r) during the previous simulated periods. This column is fixed.
M_r	Volume of methanol consumed by the chemical industry in refinery region (r).
Mr_r	Volume of methanol transferred from refinery or imported to meet U.S. methanol consumption by the chemical industry in refinery region (r).
Mt	Total volume of U.S. methanol consumption by the chemical industry, an input.
$NCL_{r,q,col}$	Coal supply curve (steps (q)), type (col), used to generate CTLs for transport to refinery region (r).
$NGA_{r,q}$	Alaska natural gas supply curve (steps (q)) used to generate GTLs for transport to refinery region (r).
$NZAMHN_q$	Volume at price discount q of Alaskan Crude (AMH) exports.
$NZAMHP_q$	Volume at price increment q of Alaskan Crude (AMH) exports.
N_rNGRFN_q	Volume at price discount (q) of natural gas in refinery region (r).
N_rNGRFP_q	Volume at price increment (q) of natural gas in refinery region (r).
$O_{c,v,b}$	Export volume of crude oil (c) with source code (v) produced in domestic region (b). At present, only Alaska exports are allowed.
O_{SPR}	Net volume of crude (foreign HL) moved to SPR.
P_b	Volume of domestic crude oil produced at producing region (b).
$Pi_{c,r,q}$	Volume of imported crude oil type (c) imported by refinery region (r) at price level (q).
$PNGL$	Alaska production of NGLs.
$Q_{p,r}$	Volume of spec product (p) manufactured in refinery region (r).
$Ra_{c,v,r}$	Crude oil volume distilled in refinery region (r) from source (v) of crude oil type (c).

Column Notation	Description
Rc_r	Manufacturing activity level for cogeneration in refinery region (r).
$Rchp_{r,m}$	Manufacturing activity level for combined heat/power burning syngas (from coke gasifier) in operating mode (m) in refinery region (r).
$Rctl_{r,m}$	Manufacturing activity level for coal to liquids (CTL) operating mode (m) in refinery region (r).
$R_{u,r,m}$	Manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).
Tu	Total volume of imported unfinished oil over all refinery regions.
$T_{i,r}$	Volume of unfinished oil component (i) processed in refinery region (r).
TAAMHXZ	Volume of AMH crude transported from Alaska to Valdez.
$TATOT_c$	Volume of crude type (c) produced in Alaska.
TAGTL	Volume of GTL transported from Alaska to Valdez.
TANSO	Volume of North Slope oil transported from Alaska to Valdez.
$TCBN_r$	Total tax levied on total carbon emissions resulting from refinery operations in refinery region (r).
$Tx_{s,p,r}$	Volume of stream (s) transferred into product (p) in refinery region (r).
$Tx_{p,p',r}$	Volume of product (p) transferred into product (p') storage in refinery region (r).
$Tx_{s,s',r}$	Volume of stream (s) transferred to stream (s') at refinery region (r).
$U_{l,r}$	Quantity of utility (l) that is purchased in refinery region (r): (l) = KWH, STM, and NGF (power, steam, and natural gas fuel) with units in thousands of kWh, Mlbs., and MMcf respectively.
Vcj	Total dead weight ton capacity of Jones Act crude oil tankers. This column is constrained to some maximum.
V_{pc}	Total dead weight tons of Jones Act product tanker of shipping class (pc). This column is constrained to some maximum.
Vcts	Total crude oil transshipped from PADD III to PADD II. This column is constrained to some maximum.

Column Notation	Description
$Vcp_{b,r}$	Total crude oil shipped by pipeline from domestic producing region (b) to refinery region (r). This column is constrained to some maximum.
$Vpp_{r,d,m}$	Total volume of light products (p) shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.
$Vtpl_{r,d,m}$	Total volume of LPG products (p) shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.
$W_{a,d,r,m}$,$W_{a,d,d',m}$	Volume of alcohol or renewable fuel (a) shipped from demand region (d) to refinery region (r) <or demand region d'> via transfer mode (m).
$W_{p,r,d,m}$	Volume of product (p) shipped from refinery region (r) to demand region (d) via transfer mode (m).
$W_{p,d,d',m}$	Volume of product (p) transshipped from demand region (d) to demand region (d') via transfer mode (m).
$WGTL_{m,r}$	Volume of GTL shipped via transfer mode (m) to refinery region (r).
$X_{p,d}$	Volume of product (p) exported from demand region (d).
$Xz_{p,d}$	Distress volume of product (p) exported from demand region (d).
$Y_{c,v,b,r,m}$	Volume of crude oil type (c) with source code (v) shipped from domestic region (b) to refinery region (r) via transfer mode (m).
Zt	Total volume of crude oil processed over all refinery regions.
ZET_d	Total volume of ethanol (from corn and cellulose) supplied from demand region (d).
Z_rFLO_u	Sum of the base, build, and expanded capacity for processing unit (u) in refinery region (r).
ZOX_r	Total quantity of percent oxygen-barrels in reformulated gasoline produced in refinery region (r).
ZZAMHTOT	Export volume of Alaskan Crude Oil.

B.4 Objective Function

The objective function has been established based on the premise that costs associated with product imports, non-crude oil inputs, and crude oil supplies are based on a given world oil price. With this in mind, the following objective function has been defined for the PMM.

Given:

$PR_{p,d}$ is the unit price of product (p) sold in demand region (d). It is the price associated with the demand volume for that product in the specified demand region, i.e. it is associated with $D_{p,d}$. Similarly, each of the other 'PR' coefficients represents the unit price of the activity it is associated with.

$PRAMH$ is the target price for Alaskan crude exports.

$PRAMHP_q$ is the premium added to the Alaskan crude target price.

C_rNGRFN_q is the discount from target natural gas fuel price in refinery region (r), to differentiate steps on the supply curve.

TE_d is the sum of Federal and State tax credits for use of ethanol in gasoline.

$C_{u,r,m}$ is the variable cost per unit of column $R_{u,r,m}$, i.e. the cost of one unit of manufacturing activity R in mode (m) operation in processing unit (u) at refinery region (r). Similarly, each of the other 'C' coefficients represents the unit cost of the activity it is associated with in the objective function as stated below.

$CAMHXZ$ is the cost of transferring Alaskan exports to Valdez.

$CAMHN_q$ is the discount from Alaskan crude target price.

C_rNGRFP_q is the premium added to the target natural gas fuel price in refinery region (r) to differentiate steps on the supply curve.

Maximize the difference between the following sum of product revenues and costs. Thus the objective function is represented as the maximization of a quantity defined by the following revenue terms:

$$\Sigma_p\Sigma_d \, D_{p,d}*PR_{p,d} + \Sigma_p\Sigma_h\Sigma_r \, H_{p,h,r}*PR_{p,h,r} + \Sigma_g\Sigma_i\Sigma_r \, H_{g,i,r}*PR_{g,i,r}$$

$$+ \, \Sigma_p\Sigma_d \, X_{p,d}*PR_{p,d} + \Sigma_p\Sigma_d \, Xz_{p,d}*PR_{p,d} + \Sigma_d \, ZET_d * TE_d + ZZAMHTOT * PRAMH$$

$$+ \, \Sigma_q \, NZAMHP_q * PRAMHP_q + \Sigma_r \, \Sigma_q \, N_rNGRFN_q * C_rNGRFN_q + \Sigma_r \, Rc_r *PR_r$$

$$+ \, \Sigma_r\Sigma_m \, Rchp_{r,m} *PR_{r,m} + \Sigma_r\Sigma_m \, Rctl_{r,m} *PR_{r,m}$$

minus the following cost terms:

$\Sigma_a\Sigma_d\Sigma_q\ B_{a,d,q}{}^*C_{a,d,q} + \Sigma_p\Sigma_r\Sigma_q\ I_{p,r,q}{}^*C_{p,r,q} + \Sigma_p\Sigma_d\ Iz_{p,d}{}^*C_{p,d} + \Sigma_b\ P_b{}^*C_b$

$+ \Sigma_c\Sigma_r\Sigma_q\ Pi_{c,r,q}{}^*C_{c,r,q} + \Sigma_i\Sigma_r\ T_{i,r}{}^*C_{i,r} + \Sigma_l\Sigma_r\ U_{l,r}{}^*C_{l,r} + \Sigma_u\Sigma_r\Sigma_m\ R_{u,r,m}{}^*C_{u,r,m}$

$+ \Sigma_u\Sigma_r\ E_{u,r}{}^*C_{u,r} + \Sigma_u\Sigma_r\ L_{u,r}{}^*C_{u,r} + \Sigma_s\ \Sigma_i\ \Sigma_r\ \Sigma_l\ W_{a,d,r,m}{}^*C_{a,d,r,m}$

$+ \Sigma_p\Sigma_r\Sigma_d\Sigma_m\ \ W_{p,r,d,m}{}^*C_{p,r,d,m} + \Sigma_p\Sigma_d\Sigma_{d'}\Sigma_m\ W_{p,d,d',m}{}^*C_{p,d,d',m}$

$+ \Sigma\ _c\Sigma_v\Sigma_b\Sigma_r\Sigma_m\ Y_{c,v,b,r,m}{}^*C_{c,v,b,r,m} + \Sigma_r\ TCBN_r + \Sigma_r\Sigma_q\ N_r NGRFP_q\ {}^*\ C_r NGRFP_q$

$+ \Sigma_q\ NZAMHN_q\ {}^*\ CAMHN_q + TAAMHXZ\ {}^*\ CAMHXZ$

$+ \Sigma_r\ M_r\ {}^*C_r + \Sigma_r\ Mr_r\ {}^*C_r + \Sigma_p\Sigma_i\Sigma_r\ H_{p,i,r}\ {}^*\ C_{p,i,r} + \Sigma_i\Sigma_r\ HMP_{FR,TO,i,,r}\ {}^*\ C_{FR,TO,i,r}$

$+ \Sigma_r\ HKWHMCH_r\ {}^*\ C_r + \Sigma_r\ \Sigma_q\ NGA_{r,q}\ {}^*C_{r,q} + PNGL\ {}^*C + TAGTL\ {}^*C + TANSO\ {}^*C$

$+ \Sigma_m\Sigma_r\ WGTL_{m,r}\ {}^*\ C_{m,r} + \Sigma_r\ \Sigma_q\ NCL_{r,q,col}\ {}^*C_{r,q,col} + \Sigma_p\Sigma_h\Sigma_d\ H_{p,h,d}{}^*C_{p,h,d}$

$+ \Sigma_p\Sigma_r\ Q_{p,r}\ {}^*\ C_{p,r} + \Sigma_i\Sigma_r\ H_{RFN,i,r}\ {}^*\ C_{i,r}$

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Note: (1) $\Sigma_u\Sigma_r\Sigma_m\ R_{u,r,m}{}^*C_{u,r,m}$ term is represented in the matrix as T(r)OVCOBJ + T(r)GPLOVC + T(r)MCHOVC as represented by rows P(r)OVC, G(r)OVC, H(r)OVC, respectively.
(2) ZZAMHTOT=TAAMHXZ as defined by row CZAMH.
(3) Row P(r)CBNTAX is used to set $TCBN_r$ regional totals for tax on carbon emissions.
(4) $Rctl_{r,m}$ in OBJ is used to capture income from electricity sales to the grid form CTL electricity cogeneration.
(5) $Q_{p,r}$ in OBJ is used to capture refinery gate markup costs.

B.5 Row Constraints

1. The implicit world oil price, WOP (the refiner's acquisition cost of imported crude oil), must be at least some fraction of premised WOP:

$$\Sigma_c \Sigma_r \Sigma_q \, Pi_{c,r,q} * C_{c,r,q} - WOP * Nwop * Zt \; \geq \; 0$$

where:

$Pi_{c,r,q}$ the volume of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q). The volume of each crude type (c) is upper bounded by each step of the supply curve.

$C_{c,r,q}$ is crude oil cost applicable to $Pi_{c,r,q}$. $/bbl

WOP   is the premised World Oil Price. $/bbl

Nwop   is minimum fraction of the WOP by which refiners must acquire crude oils by volume weighted average; and Nwop $\leq$ 1.

Zt   is total processed foreign crude oil over all refinery regions.

       I.e., the average refiner acquisition cost of crude oil will be at least some input fraction of WOP.

       Note: The index (v) denoting crude oil source is always "F" for imported crude. Therefore, no summation on (v) occurs for $Pi_{c,r,q}$.

2. The implicit world oil price, WOP (the refiner's acquisition cost of imported crude oil), must not be greater than some fraction of premised WOP:

$$\Sigma_c \Sigma_r \Sigma_q \, Pi_{c,r,q} * C_{c,r,q} - WOP * Xwop * Zt \; \leq \; 0$$

where:

Xwop   is the maximum fraction of the WOP by which refiners must acquire crude oils by volume weighted average, and Xwop $\geq$ 1.

       I.e., the average refinery acquisition cost of crude oil must not exceed some input fraction of WOP.

       Note: This constraint in conjunction with the previous constraint confines the imported crude oil volumes so that their composite unit cost is close to the WOP. Since the costs of the five types of imported crude oil bracket the WOP, there is a continuum of import possibilities. The crude oils vary in cost according to crude quality and transportation cost. However, to avoid infeasibilities due to an overly

restrictive constraint, it is presently the practice to allow a variation of 50 cents per barrel. This is also made necessary when maximum import restrictions are placed on all but a "swing" crude oil. Clearly, if the tolerance is sufficiently relaxed, a single crude type could be imported rather than a reasonably balanced mix.

3. Calculate total foreign crude oil processed by summing all crude oil volumes processed over all refinery regions:

$$\Sigma_c \Sigma_v \Sigma_r \; Ra_{c,F,r} \; - \; Zt \; = \; 0$$

where:

$Ra_{c,F,r}$ is the crude oil volume distilled in refinery region (r) from foreign source (F) of crude oil type (c).

I.e. the total U.S. refined foreign crude oil volume equals the sum of all foreign crude oils refined over all regions.

4. Place an upper bound on product import volume:

$$\Sigma_p \Sigma_r \Sigma_q \; I_{p,r,q} \;\; \leq \;\; IPmax$$

where:

$I_{p,r,q}$ is the volume of product (p) imported into refinery region (r) at cost level (q).

Ipmax   is the maximum assumed volume of imported products allowed into the United States, an input value.

I.e., the sum of product volumes imported at all price levels over all refinery regions must not exceed some maximum (set in subroutine CHGIMTOT).

5. Assure that the volumes of methanol consumed in each refinery region sum to the assumed total volume.

$$\Sigma_r \; M_r \; - \; Mt \; = \; 0$$

where:

M_r is methanol consumed by the chemical industry in refinery region (r).

Mt   is total U.S. methanol consumption by the chemical industry, an input.

I.e., methanol consumed by the chemical industry in each refinery region must sum to the projected chemical industry total (defined in *qdcrdcf.txt* input file).

Note: The PMM models domestic methanol production aggregated to the refinery region level as though the plants were processing units integral to the refinery.

The methanol production is allocated to two demands: chemical industry demand and transportation sector demand.

6. Limit capital investment for refinery expansion in each refinery region:

$$\Sigma_u \, E_{r,u} * A_{r,u} \quad \leq \quad Emax_r \quad \text{for all } r$$

where:

$E_{r,u}$ is a capacity addition for this operating year for processing unit type (u) in refinery region (r).

$A_{r,u}$ is the capital investment required per unit of capacity for processing unit type (u) in refinery region (r), million dollars per Mbbl/d.

$Emax_r$ is the upper limit on capital expenditures per year in refinery region (r), an input. $MM per year

I.e., total capital expenditures can be limited for each refinery region. This limit allows the user to place limits on expansion for a given scenario. No regional investment limits were set for the *AEO2006*. (Limits set in input file *rfinvest.txt*.)

7. Limit total U.S. refinery capital investment:

$$\Sigma_r \Sigma_u \, E_{r,u} * A_{r,u} \quad \leq \quad Emax$$

where:

Emax is the upper limit on capital investment over all refinery regions, an input. $MM

I.e., total capital expenditures are constrained to some maximum. This limit allows the user to place limits on expansion for all regions in the United States. The default value is $50 billion (set in subroutine CHGCESW) and is not constraining.

Note: This constraint has been used to determine maximum product import needs by setting Emax to zero. It has not been operative in any production runs thus far. However, like the previous row, it is a potential policy exploration handle. For instance, one could hypothesize that in a capital-short domestic environment, total industry investment is limited.

8. Limit the volume of unfinished oil processed in U.S. refineries (function of total crude through ACU):

$$\Sigma_c \Sigma_v \Sigma_r \, Ra_{c,v,r} \, - \, B1 * Tu \quad \geq \quad B0$$

where:

$Ra_{c,v,r}$ is the crude oil volume distilled in refinery region (r) from source (v) of crude oil type (c).

Tu is total processed unfinished oil over all refinery regions.

B0,B1 are regression equation coefficients (see Appendix A). B0 = 12,264, B1 = 8.1766.

I.e., the maximum allowable unfinished oil processed is a linear function of total crude oil processed.

9. Limit the volume of each unfinished oil component processed in each refinery region:

$$A_{i,r} * Tu - T_{i,r} \geq 0 \quad \text{for all} \quad r, i$$

where:

$T_{i,r}$ is the volume of unfinished oil component (i) processed in refinery region (r).

Tu is total processed unfinished oil over all refinery regions.

$A_{i,r}$ is the fraction of component (i) of total unfinished oil that is processed in refinery region (r), an input ($\Sigma_i \Sigma_r A_{i,r} = 1.0$).

I.e., the volume distribution of each type of unfinished oil processed at each refinery region is constrained to the historical pattern (set in *unfinish.dat* input).

Note: No unfinished oil is processed in PADD's II and IV.

10. Balance by volume, at the demand regions, each alcohol/renewable fuel purchased by the petroleum industry and domestic methanol shipped in from the refinery regions against alcohol/renewable fuel blended by recipe in the demand region and alcohol/renewable fuel shipped out of the demand region:

$$\Sigma_q B_{a,d,q} + \Sigma_r \Sigma_m W_{a,r,d,m} + \Sigma_{d'} \Sigma_m W_{a,d',d,m} - \Sigma_p H_{p,a,d} * A_{p,a}$$
$$- \Sigma_r \Sigma_m W_{a,d,r,m} - \Sigma_{d'} \Sigma_m W_{a,d,d',m} = 0 \quad \text{for all} \quad a, d$$

where:

$a \in h$ so that a is a subset of all recipe blends (h) (a = ETH, BIM, BIN, and MET).

$B_{a,d,q}$ is the volume of alcohol (a) purchased in demand region (d) at price level (q). At present, this column exists only for a=ETH, BIN, BIM.

$W_{a,r,d,m}$ is the volume of alcohol (a) received in demand region (d) from refinery region (r) via shipping mode (m). This column exists only for methanol (a=MET).

$W_{a,d',d,m}$ is the volume of alcohol (a) received in demand region (d) from demand region (d') via shipping mode (m). This column exists only for ethanol.

$H_{p,a,d}$ is the volume of recipe product (p) manufactured by alcohol blend recipe (a) consumed in demand region (d).

$A_{p,a}$ is the volume fraction of recipe product (p) represented by alcohol (a), an input.

$W_{a,d,r,m}$ is the volume of alcohol (a) shipped from demand region (d) to refinery region (r) via mode (m). This column is valid only for ethanol.

$W_{a,d,d',m}$ is the volume of alcohol (a) shipped from demand region (d) to demand region (d') via mode (m). This column is valid only for ethanol.

I.e., in each demand region, all alcohol/renewable that is purchased or produced and shipped in from the refinery regions must be either splash blended into or shipped to a refining center.

Note: It is assumed that all ethanol/renewables purchases are made in the demand regions. Thus, ethanol/renewables needed by the refinery for processing or blending must be shipped from the demand regions.

11. For those products which are not blended by recipe at the demand regions, for each demand region, and for each product: imports plus what is received via domestic shipment must equal the volume blended into recipes plus regular sales volume (local and exports):

$$I_{p,d} + \Sigma_r \Sigma_m W_{p,r,d,m} + \Sigma_h H_{p,h,d} - \Sigma_p \Sigma_h H_{p',h,d} * A_{p',h} - D_{p,d} - X_{p,d} - Xz_{p,d} = 0 \quad \text{for all } d, p$$

where:

$I_{p,d}$ is volume of product (p) imported into demand region (d).

$W_{p,r,d,m}$ is product (p) received in demand region (d) from refinery region (r) via transfer mode (m).

$X_{p,d}$ is volume of product (p) exported from demand region (d).

$Xz_{p,d}$ is distress volume of product (p) exported from demand region (d).

$H_{p,h,d}$ is volume of product (p) manufactured by recipe (h) at demand region (d).

$H_{p',h,d}$ is volume of product (p') manufactured by recipe (h) at demand region (d). This column exists only when product (p) is consumed to produce product (p') by a recipe blended at the demand region, i.e. splash blended at the terminals.

$A_{p',h}$ is the volume fraction of product (p') represented by product (p), consumed by recipe (h), an input.

$D_{p,d}$ is a sales volume of product (p) in demand region (d), this activity is fixed at the last NEMS iterative demand value; i.e., it does not influence the cost decision in the solution.

I.e., in each demand region, for each product, a balance is made whereby the volume imported and the volume shipped in from the refinery regions must equal the volume splash blended at the terminal plus straight sales volume.

12. Balance, at each demand region, the volumes for each of the recipe products M85 and E85 - the products which are blended at the demand terminals - so that manufactured volume plus imports equals the recipe sales volume for these terminal splash blended recipes:

$$\Sigma_h \, H_{p',h,d} + I_{p',d} - D_{p',d} \;\; = \;\; 0 \quad\quad \text{for all} \;\; p', d$$

where:

$p' \in p$ so that p' is a subset of all products and in fact, p' = E85 and M85.

$H_{p',h,d}$ is volume of recipe product (p') made by recipe (h), produced at demand region (d) by splash blending.

$I_{p',d}$ is volume of product (p') imported into demand region (d).

$D_{p',d}$ is the sales volume of product (p') in demand region (d).

I.e., for each demand region, all M85 and E85 blended at the terminals plus M85 and E85 imported into the demand region must equal sales of the corresponding products.

13. For Census Divisions (demand regions) 5 and 6, balance the volume of each product that is shipped into the demand region with volume shipped out of the demand region:

$$\Sigma_r \, \Sigma_m \, W_{p,r,d',m} + \Sigma_d \Sigma_m \, W_{p,d,d',m} - \Sigma_d \Sigma_m \, W_{p,d',d,m} \;\; = \;\; 0 \quad\quad \text{for all} \;\; d', p$$

where:

$d' \in d$ d' = Census Divisions 5 (South Atlantic) and 6 (South Central).

$W_{p,r,d',m}$ is volume of product (p) received by demand region (d') from refinery region (r) via pipeline (P/L) mode (m). These columns are generated only for the pipeline shipping mode when (d') is CD 6.

$W_{p,d,d',m}$ is volume of product (p) received in demand region (d') via transshipment from demand region (d) by mode (m), e.g. from 6 to 5 or from 5 to 2. For these columns, d' = d is not allowed.

$W_{p,d',d,m}$ is volume of product (p) transshipped from demand region (d') to demand region (d) by mode (m). However, for these columns, d' = d is allowed; in this case the activity represents P/L sales

I.e., pipeline product received in CD 5 or CD 6 must balance P/L product sales and transshipments.

Note: CD 5 and CD 2 (Mid Atlantic) receive much of their product volumes via pipeline (P/L) originating in PAD District III. Thus PAD District II production which is transported via P/L is split into one activity representing P/L product which is sold in CD 6 and another activity where the product transshipped through CD 6 into CD 5. Similarly, this latter component is split into two column activities, one which represents P/L product sales in CD 5, and another which represents product transhipped through CD 5 to CD 2.

14. Balance the domestic production of each crude type at each producing region (b) against shipments to domestic refineries (r) and exports:

Lower 48 regions (all crude types) and Alaska crude type ALL :

$$P_b * A_{c,v,b} - \Sigma_r \Sigma_m Y_{c,v,b,r,m} - O_{c,v,b} = 0 \quad \text{for all } b, c, v \quad (\text{currently, } O_{c,v,b} = 0)$$

Alaska crude type AMH only (takes into account gain due to mixing of GTLs during transport from N. Slope; exports from AK = 0 for 2005 and beyond.) :

$$P_b * A_{c,v,b} + GTLLOS * TAGTLTOT - \Sigma_r \Sigma_m Y_{c,v,b,r,m} - TAAMHXZ = 0 \quad \text{for all } b, c, v$$

where:

P_b is total volume of domestic crude oil produced at producing region (b).
NOTE: for Alaska, $P_b * A_{c,v,b} = TATOT_c$ (defined in rows CAA(c)TOT)

$A_{c,v,b}$ is the fraction by volume of P_b that is crude type (c) with source code (v), an input.

$Y_{c,v,b,r,m}$ is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m).

TAGTLTOT   is total volume of GTL transported in Alaska to Valdez.

GTLLOS   percent of GTL lost due to mixing with AK oil during transport in Alaska to Valdez.

TAAMHXZ   is total volume of AMH crude transferred from Alaska to Valdez. Only used with Alaska production region (A) row constraint.
(Note: TAAMHXZ = ZZAMHTOT as defined by row constraint CZAMH.)

I.e, for each production region and crude oil type, domestic production must be balanced against exports and shipments to refinery regions.

15. Set minimum renewables required in total US gasoline and diesel production

$$\Sigma_a \Sigma_d \Sigma_q B_{a,d,q} *A_a \geq MinRen$$

where:

a	= ETH, ETC, BIM (not BIN)
A_a	= 1.0 for ETH, BIM; = 2.5 for ETC (Renewable Fuels Standard, 2005)
$B_{a,d,q}$	Volume of ethanol/biodiesel produced in demand region d at price q (where a= ETH, ETC, BIM)
MinRen	Minimum renewables content in US production of gasoline and diesel.

16. Limit shipments of crude oil on Jones Act (with U.S. flag) marine tankers:

$$\Sigma_c \Sigma_v \Sigma_b \Sigma_r \Sigma_{m'} Y_{c,v,b,r,m'} *A_c - Vcj = 0$$

where:

$m' \in m$	m' is the set of shipping modes that correspond to Jones Act crude oil tankers.
$Y_{c,v,b,r,m'}$	is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m').
A_c	is dead weight tons per barrel of crude oil of type (c), about 0.1344.
Vcj	is total dead weight tons of Jones Act crude oil. This column is constrained to some maximum.
	I.e., total Jones act crude oil shipments are limited by the existing fleet.
	Note: This constraint is stated in the form 'X - MAX = 0' with bounds on MAX rather than in the form 'X ≤ MAX' (which is more straight forward from a mathematical standpoint) because this allows the analyst to add a minimum constraint or change to a fixed constraint within the FORTRAN code without a regeneration of the MPS file. Thus, it is an artifice of convenience.

17. Limit shipments of refined product (and GTL) on Jones Act marine tankers by product class (clean, dirty...):

$$\Sigma_{p'} \Sigma_r \Sigma_d \Sigma_{m'} W_{p',r,d,m'} *A_{p'} + \Sigma_p \Sigma_r \Sigma_d \Sigma_{m'} W_{GTL,A,r,m'} *A_{GTL} - V_{pc} = 0 \quad \text{for all product class (pc)}$$

where:

$m' \in m$	m' is the set of shipping modes that correspond to Jones Act product tankers carrying product class (pc).
$p' \in p$	p' is the set of products which correspond to the product class (pc) of the particular constraint row.
$W_{p',r,d,m'}$	is volume of product (p') shipped from refinery region (r) to demand region (d) via mode (m').
$A_{p'}$	is dead weight tons per barrel of product (p'), an input.
$W_{GTL,A,r,m'}$	is volume of product GTL shipped from Alaska to refinery region (r) via mode (m').
A_{GTL}	is dead weight tons per barrel of GTL, an input.
V_{pc}	is total dead weight tons of Jones Act product of a shipping class (pc). This column is constrained to some maximum.
	I.e., Jones Act product shipment volume is limited by tanker availability.

18. For each domestic crude oil producing region and refinery region (r) allowable combination, allow and limit pipeline shipments of crude oil:

$$\Sigma_c \Sigma_v \Sigma_m\ Y_{c,v,b,r,m} - Vcp_{b,r}\ =\ 0 \qquad \text{for all}\quad b, r$$

where:

$Y_{c,v,b,r,m}$	is volume of crude oil type (c) that is shipped from domestic producing region (b) to refinery region (r) via pipeline mode (m).
$Vcp_{b,r}$	is total crude oil shipped by pipeline from domestic producing region (b) to refinery region (r). This column is constrained to some maximum.
	I.e., limit the crude oil volume shipped by pipeline from each applicable producing region//refinery region pair.

19. For each refinery/demand region applicable combination, limit pipeline shipments of light products to available capacity:

$$\Sigma_p \Sigma_r \Sigma_d \Sigma_m\ W_{p',r,d,m} - Vpp_{r,d,m}\ =\ 0 \qquad \text{for all}\quad r, d, m$$

where:

$p' \in p$	p' is the set of light products which can be shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$W_{p',r,d,m}$ is volume of product (p') shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$Vpp_{r,d,m}$ is total volume of light products (p') shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.

I.e., the volume of light products that can be shipped by pipeline from each refinery region to each demand region is limited by the available pipeline capacity.

Note: Special cases exist for transfer from CD 6 to CD 5, from CD 5 to CD 2, from CD 6 to CD 6 (P/L sales), and from CD 5 to CD 5 (P/L sales).

20. For each refinery/demand region applicable combination, limit pipeline shipments of liquid petroleum gas and PCF volumes to available LPG pipeline capacity:

$$\Sigma_{p'}\Sigma_r\Sigma_d\Sigma_m \, W_{p',r,d,m} - Vtpl_{r,d,m} = 0 \quad \text{for all } r, d, m$$

where:

$p' \in p$ p' is the set of LPG and PCF products which can be shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$W_{p',r,d,m}$ is volume of LPG and PCF product (p') shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$Vtpl_{r,d,m}$ is total volume of LPG and PCF products (p') shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.

I.e., the volume of LPG products that can be shipped by pipeline from each refinery region to each demand region is limited by the available pipeline capacity.

Note: Special case exists for transfer from CD 6 to CD 5.

21. Refinery 'policy' table entries are adhered to:

$$\Sigma_u\Sigma_m \, R_{u,r,m} * A_{e,u,r,m} - A_{e,r} * Z_r FLO_u \quad \leq, \geq, = 0 \quad \text{for all } e, r$$

where:

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{e,u,r,m}$ is the coefficient entered into the processing unit (u) table for refinery region (r) in the operating mode (m) column at policy row (e), an input.

$A_{e,r}$ is the fractional amount of total capacity value entered in the policy table in row (e) for refinery region (r), an input, i.e., constraints may be introduced by the analyst via the "policy" rows.

Note: The type of row ($\leq, \geq, =$) is determined by the entry in column heading TYPE of the policy table (r)POL (located in *setrows.dat* input file) where $A_{e,r}$ appears. It may also be a non-constraining row, in which case the row is free. The total processing unit throughput is the base for the policy limits in each refinery region:

$$Z_r FLO_u - K_{u,r} - A_{u,r}*(L_{u,r} + E_{u,r}) = 0 \quad \text{for all} \quad r, u$$

where:

$Z_r FLO_u$ is the sum of the base, build, and expanded capacity in processing unit (u) at refinery region (r).

$K_{u,r}$ is the base processing capacity in processing unit (u) at refinery region (r) in Mbbl/cd. This column is upper bounded rather than fixed.

$A_{u,r}$ is the stream factor for processing unit (u) at refinery region (r) defined as the ratio of calendar day capacity to stream day capacity.

$L_{u,r}$ is the cumulative stream day capacity added for processing unit (u) at refinery region (r) during the previous simulated periods. This column is fixed.

$E_{u,r}$ is the stream day capacity added during this simulated period for processing unit (u) at refinery region (r). This column is generally upper bounded.

22. For each applicable combination of domestic crude oil and refinery region, balance shipments received directly from the producing region plus transshipments received from other refinery regions against crude oil consumed at the refinery and crude that is transshipped to other refinery regions:

$$\Sigma_b \Sigma_m Y_{c,v,b,r,m} + \Sigma_{r'} \Sigma_m Y_{c,v,r',r,m} - \Sigma_{r'} \Sigma_m Y_{c,v,r,r',m} - Ra_{c,v,r} = 0 \quad \text{for all} \quad c, v, r$$

where:

$Y_{c,v,b,r,m}$ is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m).

$Y_{c,v,r',r,m}$ is volume of domestic crude oil type (c) with source code (v) that is received at refinery region (r) by transshipment through refinery region (r') via mode (m).

$Y_{c,v,r,r',m}$ is volume of domestic crude oil type (c) with source code (v) that is transshipped through refinery region (r) to refinery region (r') via mode (m).

$Ra_{c,v,r}$ is volume of domestic crude oil type (c) with source code (v) that is processed through the atmospheric tower at refinery region (r).

I.e., for each domestic crude oil at each refinery region, the volume consumed at the refinery plus what is shipped out of the refinery region must equal what is shipped into the refinery region.

23. For each applicable combination of imported crude oil and refinery region, balance imports received directly plus imports transshipments received from other refinery regions against crude oil consumed at the refinery and crude that is transshipped to other refinery regions:

$$\Sigma_q \; Pi_{c,r,q} \; + \; \Sigma_r \Sigma_m \; Y_{c,F,r',r,m} \; - \; \Sigma_r \Sigma_m \; Y_{c,F,r,r',m} - Ra_{c,F,r} \; - \; O_{SPR} \; = \; 0 \quad \text{for all} \;\; c, r$$

where:

$Pi_{c,r,q}$ is the quantity of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q).

$Y_{c,F,r',r,m}$ is volume of imported crude oil type (c) that is received at refinery region (r) by transshipment from refinery region (r') via mode (m).

$Y_{c,F,r,r',m}$ is volume of imported crude oil type (c) that is transshipped from refinery region (r) to refinery region (r') via mode (m).

$Ra_{c,F,r}$ is volume of imported crude oil type (c) that is processed through the atmospheric tower at refinery region (r).

O_{SPR} volume of imported oil moved to the Strategic Petroleum Reserve in PADD III

            I.e., each imported crude oil must be balanced at each refinery by matching imports and what is received through transshipment against refinery consumption and what is transshipped to other refineries or to the SPR.

24. Balance each product at each refinery region:

$$Q_{p,r} + \Sigma_i H_{p,i,r} + \Sigma_q \; I_{p,r,q} + \Sigma_{p'} \; Tx_{s,p,r} - \Sigma_u \Sigma_m \; R_{u,r,m} * A_{p,u,r,m}$$

$$- \; \Sigma_m \Sigma_d \; W_{p,r,d,m} \; = \; 0 \quad \text{for all} \;\; p, r$$

where:

$Q_{p,r}$ is volume of spec product (p) manufactured in refinery region (r). When product (p) is a spec product, column $H_{p,h,r}$ does not exist.

$H_{p,i,r}$ is volume of product (p) generated from gas plant stream (i) in refinery region (r). (Also includes $H_{p,h,r}$.) When this column is active for product (p), column $Q_{p,r}$ does not exist.

$I_{p,r,q}$ is volume of refined product (p) imported into refinery region (r) at price level (q).

$Tx_{s,p,r}$ is the volume of stream (s) transferred into product (p) in refinery region (r).

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r). (Applicable to product N6I and N6B only.)

$A_{p,u,r,m}$ is the volume fraction of manufacturing activity level in mode (m) operation in processing unit (u) which defines the volume of product (p) produced (or consumed if the sign is negative) per unit of manufacturing activity level in refinery region (r).

$W_{p,r,d,m}$ is the volume of product (p) shipped from refinery region (r) to demand region (d) via mode (m).

I.e., for each product at each refinery, the volume manufactured plus volume imported plus volume transferred from another higher quality product must equal to the volume transferred to other lower quality products plus the amount consumed by recipe plus the volume shipped to market.

25. Balance each utility at each refinery region:

$$U_{l,r} + \Sigma_u \Sigma_m R_{u,r,m} * A_{l,u,r,m} - \Sigma_p Q_{p,r} * A_{l,p,r} - \Sigma_p \Sigma_h H_{p,h,r} * A_{l,h,r} \quad = \quad 0 \quad \text{for all} \quad r, l$$

where:

$U_{l,r}$ is the quantity of utility (l) that is purchased in refinery region (r). (l) = KWH, STM, and NGF (power, steam, and natural gas fuel) with units in thousands of kWh, lbs., and Mcf respectively.

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{l,u,r,m}$ is the quantity of utility (l) consumed (-) or manufactured (+) per unit of operation of processing unit (u) in mode (m) in refinery region (r). The (u) index includes the utility manufacturing units.

$Q_{p,r}$ is the volume of spec product (p) manufactured at refinery region (r). This column exists only when product (p) is a spec blend.

$A_{l,p,r}$ is the quantity of utility (l) consumed per unit of spec product (p) manufactured at refinery region (r).

$H_{p,h,r}$ is the volume of product (p) manufactured by recipe blend (h) at refinery region (r). This column exists only when product (p) is a spec blend.

$A_{l,h,r}$ is the quantity of utility (l) consumed per unit of recipe product (h) manufactured at refinery region (r).

I.e., for each utility at each refinery region, the quantity purchased plus the amount manufactured must equal the consumption.

26. Constrain each processing unit throughput to maximum capacity at each refinery region:

$$\Sigma_m R_{u,r,m} - K_{u,r} - A_{u,r}*(L_{u,r} + E_{u,r}) \;\; = \;\; 0 \qquad \text{for all} \;\; r, u$$

where:

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$K_{u,r}$ is the base processing capacity in processing unit (u) at refinery region (r) in Mbbl/cd. This column is upper bounded rather than fixed. See note below.

$A_{u,r}$ is the stream factor for processing unit (u) at refinery region (r) defined as the ratio of calendar day capacity to stream day capacity.

$L_{u,r}$ is the cumulative stream day capacity added for processing unit (u) at refinery region (r) during the previous simulated periods. This column is fixed.

$E_{u,r}$ is the stream day capacity added during this simulated period for processing unit (u) at refinery region (r). This column is generally upper bounded.

I.e., the activity of a particular processing unit must be limited to the maximum operating capacity.

Note: By making this row fixed with the base capacity upper bounded, the processing throughput is calculated as $K_{u,r} + A_{u,r}*(L_{u,r} + E_{u,r})$. In a model lacking capacity expansion capability, the capacity constraint row is commonly constructed as throughput and is equal to or less than a right-hand-side capacity value so that the throughput is merely the row activity.

27. Balance each intermediate refinery stream at each refinery region:

$$\Sigma_u\Sigma_m R_{u,r,m}*A_{i,u,r,m} + \Sigma_s (Tx_{s,i,r} - Tx_{i,s,r}) - \Sigma_p G_{i,p,r} - \Sigma_p\Sigma_h H_{p,i,r}*A_{i,h} - Mr_r = 0 \qquad \text{for all} \;\; i, r$$

where:

$i \in s$ i.e., the intermediate streams are a subset of all refinery streams.

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{i,u,r,m}$ is the volume fraction of intermediate stream (i) created (or consumed if the sign is negative) per unit of manufacturing activity level in mode (m) operation for processing unit (u) at refinery region (r).

$Tx_{s,i,r}$ is the volume of stream (s) transferred to intermediate stream (i) at refinery region (r).

$Tx_{i,s,r}$ is the volume of intermediate stream (i) transferred to stream (s) at refinery region (r).

$G_{i,p,r}$ is the volume of intermediate stream (i) blended into spec blended product (p) at refinery region (r).

$H_{p,i,r}$ is volume of product (p) generated from gas plant stream (i) in refinery region (r). (Also includes $H_{p,h,r}$. and $H_{RFN,i,r}$)

$A_{i,h}$ is the volume fraction of product (p) for which intermediate stream (i) is consumed (per unit volume of product manufactured) according to recipe (h) at refinery region (r).

Mr_r Volume of methanol transferred from refinery or imported to meet U.S. methanol consumption by the chemical industry in refinery region (r). (only used with methanol balance B(r)MET, G(r)MET)

     I.e., at each refinery region, each intermediate stream must be volume balanced so that the amount manufactured plus the amount transferred from higher quality streams must equal the volumes consumed by manufacturing processes, the amount that may be transferred to other lower quality streams plus the volumes blended into spec and recipe products.

28. Constrain qualities of spec blended products:

$$\Sigma_i \ G_{i,p,r}*A_{y,i,p} - Q_{p,r}*A_{y,p,r} \quad \leq, \geq, = \quad 0 \qquad \text{for all} \quad y, p, r$$

where:

$G_{i,p,r}$ is the volume of intermediate stream (i) blended into spec-blended product (p) at refinery region (r).

$A_{y,i,p}$ is the blend value of spec blend property (y) for spec product (p) of stream (i).

$Q_{p,r}$ is the total volume of spec-blended product (p) manufactured at refinery region (r).

$A_{y,p,r}$ is the constraining value of property (y) that spec product (p) must adhere to; e.g., an octane number, at refinery region (r).

     Note: The row type varies depending upon whether the blend specification quality is a maximum, minimum, or fixed value.

i.e., for each spec for each product at each refinery region, the aggregate spec value of the product determined by volume weighting the spec properties of the consumed blending stocks must not violate the specification limit.

29. Balance blending rows with specific blended products:

$$\Sigma_i G_{i,p,r} - \Sigma_{p'} Q_{p',r} = 0 \quad \text{for all} \quad p, r$$

where:

p   is only TRG, RFG, N6I, N6B, DSL, DSU, N2H, and JTA.

$p' \in p$ for p=TRG, p'=TRG, TRH, SST, SSE;
for p=RFG, p'=RFG, RFH, SSR;
for remaining products (p), p'=p only (i.e., for JTA, p'=JTA only).

$G_{i,p,r}$ is the volume of intermediate stream (i) blended into spec-blended product (p) at refinery region (r).

$Q_{p',r}$ is the total volume of spec-blended product (p) manufactured at refinery region (r).

30. Sum oxygen percentage contribution by oxygenates blended to reformulated gasoline

$$\Sigma_{OX} G_{OX,RFG,r} * PO_{OX} + \Sigma_{d \in r} H_{ETH,RFG,d} * PO_{ETH} * F_{ETHRFG} + \Sigma_{d \in r} H_{ETH,RFH,d} * PO_{ETH} * F_{ETHRFH} - ZOX_r = 0 \quad \text{for all} \quad r$$

where:

$G_{OX,RFG,r}$ is the volume of oxygenate stream (OX) blended to RFG in region (r).

PO_{OX} is the percentage oxygen in oxygenate stream (OX). This group includes MTBE, TAM, and THM from methanol and ETBE, TAE, and THE from ethanol. Also included is the ethanol splash blended.

$H_{ETH,RFG,d}$ is the volume of RFG splash blended with ethanol in demand region d (within region r).

PO_{ETH} is the percentage oxygen in ethanol

F_{ETHRFG} is the fraction of ethanol in RFG for 2.0 percent min oxygen (= 5.8 percent).

$H_{ETH,RFH,d}$ is the volume of RFH splash blended with ethanol in demand region d (within region r).

F_{ETHRFH} is the fraction of ethanol in RFH for 2.7 percent min oxygen (= 7.8 percent).

ZOX_r is the total volume in units of percent oxygen-barrels of RFG.

31. Sum oxygen percentage contribution by *renewable oxygenates* blended to RFG.

$$\Sigma_{OE}\, G_{OE,RFG,r}\, *PO_{OE} + \Sigma_{d\in r}\, H_{ETH,RFG,d}\, *PO_{ETH}\, *F_{ETHRFG} + \Sigma_{d\in r}\, H_{ETH,RFH,d}\, *PO_{ETH}\, *F_{ETHRFH} - L*ZOX_r \geq 0 \qquad \text{for all} \quad r$$

where, in addition to the terms defined in equation 30:

$G_{OE,RFG,r}$ is the volume of renewable oxygenate stream (OE) blended to RFG in region (r).

PO_{OE} is the percentage oxygen in oxygenate stream (OE). This group includes ETB, TAE, and THE from ethanol. Also included is the ethanol splash blended.

L is the volume fraction of the oxygen that must come from *renewable oxygenates*, i.e., ethanol, ethylbenzene (ETB) and ethyl ethers (TAE and THE).

32. Calculate refinery consumption of natural gas supply by summing volumes processed for each refinery region:

$$\Sigma_q N_r NGRFN_q + \Sigma_q N_r NGRFP_q - U_r NGF = 0$$

where:

$N_r NGRFN/P_q$ is the volume of natural gas consumed in refinery region (r) at supply price delta (q).

$U_r NGF$ is the total volume of natural gas consumed in refinery region r.

33. Place an upper bound on each natural gas supply step volume:

$$N_r NGRFN/P_q \leq NG_q\, max$$

where:

$N_r NGRFN/P_q$ is the volume of natural gas allowed on step q in region (r) at cost a cost delta.

$NG_q\, max$ is the maximum volume of natural gas supply allowed, based on an input value. Note that step N1 has a minimum lower bound volume.

34. Calculate Alaskan crude export volumes:

$$\Sigma_q\, NZAMHP_q + \Sigma_q\, NZAMHN_q - ZZAMHTOT = 0$$

where:

Σ_q NZAMHP$_q$ Volume at price increment q of Alaskan Crude (AMH) exports.

Σ_q NZAMHN$_q$ Volume at price discount q of Alaskan Crude (AMH) exports.

35. Place an upper bound on each Alaskan crude supply step volume:

$$\text{NZAMHx}_q \geq \text{NZAMHx}_q \text{ max}$$

where:

NZAMHx$_q$ Volume at price increment/discount q of Alaskan Crude (AMH) exports.

NZAMHx$_q$max is the maximum volume of crude export allowed, based on an input value.

36. Calculate taxable carbon emissions:

$$\text{TCBN}_r - \Sigma_m R_{FUM, r,m} = 0 \qquad \text{for all } r$$

where:

TCBN$_r$ Total carbon emissions resulting from refinery operations in refinery region r for which tax is levied.

R$_{FUM, r,m}$ is the manufacturing activity level in mode (m) operation in processing unit FUM at refinery region (r).

37. Calculate ethanol available for tax subsidy:

$$\Sigma_q B_{a,d,q} - \text{ZET}_d = 0 \qquad \text{for all } d, a = \text{ETH, ETC}$$

where:

ZET$_d$ Total ethanol production in demand region d for which tax subsidy is allowed.

B$_{a,d,q}$ Volume of ethanol produced in demand region d at price q (where a= ETH, ETC)

38. Calculate volume of GTL movement from Alaska to refining regions:

$$\Sigma_m W_{GTL,A,r,m} - \Sigma_i \text{HMP}_{i,r} = 0 \qquad \text{for all } r$$

where:

W$_{GTL,A,r,m}$ Total GTL transferred from Alaska to region r via transportation mode m

39. Limit volume percent of undesirable oxygenate in RFG (and TRG) - related motor gasoline (mogas) produced at refinery r for sale or splash blending:

$$\Sigma_{ox} G_{ox,RFG,r} - \Sigma_{mg \in RFG} Q_{mg,r} * PO_{mg} \leq 0 \qquad \text{for all } r$$

and

$$\Sigma_{ox} G_{ox,TRG,r} - \Sigma_{mg \in TRG} Q_{mg,r} * PO_{mg} \leq 0 \qquad \text{for all } r$$

where:

$G_{ox,TRG,r}$ Volume of oxygenate ox (MTBE, ETBE, TAE, TAM for TRG component) blended or splash blended in the manufacture of TRG mogas components.

$G_{ox,RFG,r}$ Volume of oxygenate ox (MTBE, ETBE, TAE, TAM, THE, THM for RFG component) blended or splash blended in the manufacture of RFG mogas components.

$Q_{mg,r}$ Volume of spec product mg (SST, SSE, TRG, TRH for TRG component, and SSR, RFG, RFH for RFG component) manufactured in refinery region r.

PO_{mg} Percentage oxygen required in mogas component mg.

40. Maximum and minimum flow requirements along TAPS in Alaska:

$$TANSOTOT \ + \ TAGTLTOT \ > \ NSOmin$$

and

$$TANSOTOT \ + \ TAGTLTOT \ < \ NSOmax$$

where:

TANSOTOT   Total oil transported from Alaska North Slope to Valdez along TAPS. (defined in row CANSOTOT)

TAGTLTOT   Total GTL transported fron Alaska North Slope to Valdez along TAPS. (defined in row CAGTLTOT)

NSO   Min and Maximum (capacity) flow allowed on TAPS in Alaska.

41. Maximum natural gas available for processing to GTL in Alaska:

$$\Sigma_r \, \Sigma_q \, NGA_{r,q} \quad \leq \quad NGmax$$

$NGA_{r,q}$ Natural gas used at price q to generate GTL for transport to refinery region r

NSO   Maximum quantity of natural gas allowed to be consumed for GTL production in Alaska.

42. Place an upper or lower bound on selected refinery fuels used in all US refining regions:

$$\Sigma_r \, \Sigma_m \, R_{u,r,m} \quad \leq \ or \geq \ MFuel_f \qquad \qquad for \ all \quad m \in refinery \ fuel_f$$

where:

u   = FUM only

f   includes refinery fuel types LPG, RES, STG, and OTH only.

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u=FUM) at refinery region (r); $m \in$ refinery $fuel_f$ (ie, m=N6I, N6B, N6A for f=RES).

MFuel$_f$ is the maximum (or minimum) volume of fuel (f) allowed to be consumed as fuel at US refineries. This is based on historical levels, with analyst judgment used to allow for growth. Currently, the growth rate per year for the LPG upper bound is 10% for the base AEO run, with side case runs at 12% for LWOP, 6% for HWOP, 8% for LMAC, and 11% for HMAC. The minimum bound for STG, RES, and OTH grows at 0.3% per year for all cases.

43. For each applicable combination of imported crude oil and refinery region, total imports received directly to the U.S. must be greater than a minimum:

$$\Sigma_c \, \Sigma_r \, \Sigma_q \, Pi_{c,r,q} \geq rhs \qquad\qquad \text{for all } c \in \text{foreign crude}$$

where:

$Pi_{c,r,q}$ is the quantity of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q).

rhs   lower limit on total imports of foreign crude (currently set to 10.045 MM bbl/cd, and zero for HWOP)

44. For each applicable combination of imported crude oil and refinery region, total imports received directly to refining region r must be less than a maximum:

$$\Sigma_c \, \Sigma_q \, Pi_{c,r,q} \leq rhs \qquad\qquad \begin{array}{l} \text{for all } c \in \text{foreign crude} \\ \text{only for r=PADD II or PADD IV} \end{array}$$

where:

$Pi_{c,r,q}$ is the quantity of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q).

rhs   upper limit on total imports of foreign crude into PADD II or IV only (limit on Canadian imports).
       PADD II: rhs = 1212 * cangrw**(curiyr-16)
       PADD IV: rhs = 266   * cangrw**(curiyr-16)
     where, cangrw   = 1.008 for all, except HWOP
                     = 1.011 for HWOP

45. For PADD II and PADD IV only, total product imports received directly to refining region r must be less than a maximum:

$$\Sigma_p \, \Sigma_q \, I_{p,r,q} \leq rhs \qquad\qquad \text{only for r = PADD II, IV only}$$

where:

$I_{p,r,q}$ is volume of refined product (p) imported into refinery region (r=PADD II or IV) at price level (q).

rhs   upper limit on total imports of refinery product into PADD II or IV only (limit on Canadian imports).

PADD II: rhs = 108 * cangrw**(curiyr-16)
PADD IV: rhs = 15.6 * cangrw**(curiyr-16)
where, cangrw   = 1.03 for all, except HWOP
                        = 1.04 for HWOP

46. For all Census Division exporting refinery products, total exports of coke must be greater than a minimum:

$$\Sigma_d\, X_{p,d} \geq rhs \qquad\qquad only\ for\ p = coke$$

where:

$X_{p,d}$ is volume of product (p=coke) exported from demand region (d).

rhs lower limit on total export of coke (currently set to 380 M bbl FOE/cd)

47. For PADD I only, imports of SSR for blend with ethanol must be less than a maximum (to account for localized attainment areas and MTBE ban requirements):

$$\Sigma_q\, I_{p,r,q} \leq rhs \qquad\qquad only\ for\ r = PADD\ I,\ p = SSR$$

where:

$I_{p,r,q}$ is volume of refined product (p=SSR) imported into refinery region (r=PADD I) at price level (q).

rhs upper limit on SSR splash blended imports into Padd I (currently not constraining)

48. For each refining region, the ethane transferred to LPG must not exceed the amount extracted as liquids from the gas plant (should not include ethane transferred to gas plant):

$$\Sigma_q\, H_{p,i,r}\ -\ \Sigma_m\, A_{i,u,r,m} * R_{u,r,m} \leq 0.0 \qquad only\ for\ i = PGS,\ p=LPG,\ CC1,\ u=gas\ plant$$

where:

$A_{i,u,r,m}$ is the volume fraction of intermediate stream (i) created (or consumed if the sign is negative) per unit of manufacturing activity level in mode (m) operation for processing unit (u) at refinery region (r). (special case: u=gas plant, i=pgs)

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u= gas plant) at refinery region (r).

$H_{p,i,r}$ Volume of product (p) from gas plant stream (i) in refinery region (r).

49. Limit total ACU capacity addition in a single year:

$$\Sigma_r\, E_{r,u}\ \leq\ ACU_{max} \qquad\qquad for\ u=ACU\ only$$

where:

$E_{r,u}$ is a capacity addition for this operating year for processing unit type (u=ACU) in refinery region (r).

ACU_{max} is the maximum total ACU build allowed in one decision year (= 1000000 bbl/cd)

50. Limit total coal-to-liquids (CTL) facilities allowed to penetrate the market in a single year by putting an upper limit on the summation variable E@CTXINV:

$$\text{E@CTXINV} \ - \ \Sigma_r \, E_{r,u} \ = \ 0.0 \qquad\qquad \text{for u=CTX only}$$

where:

$E_{r,u}$ is a capacity addition for this operating year for processing unit type (u=CTX) in refinery region (r).

E@CTXINV is the total CTL builds allowed in one decision year (with UL set based on the Mansfield-Blackman penetration algorithm—see Appendix F.18)

51. Set national imports of light, sweet (LL) crude to a lower limit based on historical levels, phased out over the forecast:

$$\Sigma_r \, \Sigma_q \, Pi_{c,r,q} \ \geq \ \text{rhs} \qquad\qquad \text{for c=FLL only}$$

where:

$Pi_{c,r,q}$ is the quantity of imported crude oil acquired by refinery region (r) of crude type (c=FLL) at price level (q).

rhs lower limit on total imports of foreign light, sweet crude into the U.S.

52. Limit total growth in cellulose ethanol plant expansion a maximum of an additional 1 to 2 units per year:

$$\Sigma_d \, \Sigma_q \, B_{a,d,q} \ \leq \ \text{rhs} \qquad\qquad \text{for a=ETC only}$$

where:

$B_{a,d,q}$ Volume of ethanol produced in demand region d at price q (where a= ETC)

rhs upper limit on total cellulose ethanol produced in the U.S.

53. Limit total MTBE and ETBE produced for gasoline blending per calendar day:

$$\Sigma_u \, \Sigma_r \, \Sigma_m \, R_{u,r,m} \ \leq \ \text{rhs} \qquad\qquad \text{for u=ETX, ETH only}$$

where:

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u= ETX, ETC plant) at refinery region (r).

rhs   upper limit on total MTBE and ETBE produced for gasoline blending in the U.S.

54. In addition to the above, numerous non-constraining rows exist merely as a convenience to sum over certain columns via the row activity parameter. These include, but are not limited to, rows C(r)CTLTOT, E(r)(emis)(N,C), P(r)LOS, G(r)LOS, H(r)LOS, O(b)(v)(c), P(r)(e)*, A(r)DSLCTI, A(r)DSUCTI, A(r)RFGM00, A(r)RFGR00, A(r)TRGM00, A(r)TRGR00, and other A-rows.

* Note: not all rows with this form are non-constraining.

B.6 Row and Column Cross References

The PMM LP matrix is generated from a program written in the FORTRAN language using callable subroutines from OML. The correspondence between the rows and the column symbols in the preceding matrix description and the generated matrix names of PMM are shown in Table B4.

Table B4. Column Cross References

Column Notation	Matrix Name
$B_{a,d,q}$	C(d)(a)R(q)
$D_{p,d}$	D(d)(p)S1
$E_{u,r}$	E(r)(u)INV
$G_{i,p,r}$	B(r)(p)(i) & F(r)(p)(i)
$H_{p,h,r}$	X(r)(h)(p)
$H_{p,h,d}$	X(d)(h)(p)
$H_{p,i,r}$, $H_{RFN,i,r}$	G(r)(i)(p)
$H_{g,i,r}$	G(r)(i)(g)
$HKWHMCH_r$	H(r)KWHMCH
$HMP_{i,r}$	H(r)MPRF(i), H(r)MPGP(i), H(r)RFMP(i), H(r)GPMP(i)
$I_{p,r,q}$	I(r)(p)R(q)
$Iz_{p,d}$	I(d)(p)Z9
$K_{u,r}$	K(r)(u)CAP
$L_{u,r}$	L(r)(u)BLD
M_r	G(r)METDEM
Mr_r	G(r)RFNMET
Mt	D@METS1
$NCL_{r,q,col}$	N(r)(col)N(q)
$NGA_{r,q}$	N(r)NGKN(q)
N_rNGRFN_q	N(r)NGRFN(q)

Column Notation	Matrix Name
N_rNGRFP_q	N(r)NGRFP(q)
$NZAMHN_q$	NZAMHN(q)
$NZAMHP_q$	NZAMHP(q)
$O_{c,v,b}$	O@CRDEXP
O_{SPR}	O@CRDSPR
P_b	P(b)DCRQ1
$Pi_{c,r,q}$	P(r)F(c)Q(q)
PNGL	PANGLQ1
$Q_{p,r}$	Q(r)(p)
$Ra_{c,v,r}$	R(r)ACU(v)(c)
Rc_r	R(r)CGNCGN, R(r)CGXCGN
$Rchp_{r,m}$	R(r)CHP(mod)
$Rctl_{r,m}$	H(r)CTX(mod), H(r)CTZ(mod)
$R_{u,r,m}$	R(r)(u)(m) & H(r)(u)(m)
Tu	T@UNFTOT
$T_{i,r}$	T(r)UNF(i)
TAAMHXZ	TAAMHXZ
$TATOT_c$	TAA(c)TOT
TAGTL	TAGTLTOT
TANSO	TANSOTOT
$TCBN_r$	T(r)CBNTAX
$Tx_{s,p,r}$	T(r)(s)(p)
$Tx_{p,p',r}$	T(r)(p)(p')
$Tx_{s,s',r}$	T(r)(s)(s')
$U_{l,r}$	U(r)(l)
U_rNGF	U(r)NGF

Column Notation	Matrix Name
Vcj	VTVC(m)CP
V_{pc}	VTVP(m)CP
$Vcts$	VTPCGAC (not used)
$Vcp_{b,r}$	VTPC(b)(m)(r)
$Vpp_{r,d,m}$	VTPP(r)(m)(d)
$Vtpl_{r,d,m}$	VTPL(r)(m)(d)
$WGTL_{m,r}$	WAGTL(m)(r)
$W_{a,r,d,m}$	W(r)(a)(m)(d) [a=MET]
$W_{a,d,r,m}$, $W_{a,d,d',m}$	W(d)(a)(m)(r), W(d)(a)(m)(d')
$W_{p,r,d,m}$	W(r)(p)(m)(d)
$W_{p,d,d',m}$	W(d)(p)(m)(d')
$X_{p,d}$	D(d)(p)SX
$Xz_{p,d}$	D(d)(p)Z9
$Y_{c,v,b,r,m}$	Y(b)(v)(c)(m)(r)
Zt	Z@TOTCRD
ZET_d	Z(d)ETHTAX Z(d)ETCTAX
Z_rFLO_u	Z(r)FLO(u)
ZOX_r	Z(r)RFGOXY
ZZAMHTOT	ZZAMHTOT

Table B5. Row Cross References

Row Number	Matrix Name
1	Z@IRACN
2	Z@IRACX
3	Z@CRDTOT
4	A@PRDIMP
5	D@MET
6	A(r) INVST
7	A@INVST
8	F@TOTCRD
9	F(r)UNF(i)
10	D(d)(a)
11	D(d)(p)
12	D(d)(p') [E85,M85]
13	M(d)(p)
14	C(b)(v)(c), (CZAMH), CAALLTOT, CAAMHTOT
15	C@ETHBIO
16	TVC(m)CP
17	TVP(m)CP
18	TPC(b)(m)(r)
19	TPP(r)(m)(d)
20	TPL(r)(m)(d)
21	P(r)(e), H(r)(e), G(r)(e), Z(r)CAP(u)
22	C(r)(v)(c)
23	C(r)F(c)
24	M(r)(p)
25	U(r)(l), H(r)(l)
26	L(r)(u)CAP, H(r)FUMCAP
27	B(r)(i), G(r)(i), H(r)(i)
28	Q(r)(p)(y)
29	S(r)(p)E
30	S(r)RFGOXY
31	Q(r)RFGREN
32	Z(r)NGFSUM
33*	N(r)NGRFN/P(q)
34	ZZAMHSUM
35*	NZAMHN/P(q)
36	P(r)CBNTAX
37	A(d)ETHTAX, A(d)ETCTAX
38	C(r)GTL
39	M(r)MTBRFG, M(r)MTBTRG
40	TAOILGTN, TAOILGTX, CANSOTOT, CAGTLTOT
41	TANGKGTX

Row Number	Matrix Name
42	A@(f)FU
	[LPG,RES,OTH,STG]
43	A@CRDIMP
44	A(r)CRDIMP [Padds 2,4 only]
45	A(r)PRDIMP [Padds 2,4 only]
46	A@COKEXP
47	A(r)SSRIMP [Padd 1 only]
48	G(r)PGSLGX, G(r)SC2C1X
49	A@1YRBLD
50	E@CTXMBX
51	Z@FLLIMP
52	A@ETCPRD
53	A@MTBPRD
54	(misc)

* Bound on column variable.

APPENDIX C

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APPENDIX C Bibliography

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77.   U.S. Department of Agriculture, *USDA Agricultural Baseline Projections to 2009*, Staff Report WAOB-00-1 (Washington, DC, September 2000).

78.   U.S. Department of Energy, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions, and Results, Technical Annex 2, First Addition, 1991/1992, DOE/S-0086P, p.148.

79.   U.S. Department of Energy, *National Energy Strategy* (Washington, DC, February 1991).

80.   U.S. Department of Energy, *Review of the Component Design Report for the Petroleum Market Module*, memorandum prepared by A.E. Haspel (Washington, DC, June 1992).

81.   U.S. Department of Energy, *Review of the Component Design Report for the Petroleum Market Module*, memorandum prepared by J.D. Pearson (Washington, DC, June 1992).

82.   U.S. Environmental Protection Agency, *Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel*; Final Rule, 40 CFR, Parts 9, 69, et al.

83.   U.S. Environmental Protection Agency, Heavy-Duty Engines and Vehicle Standards and Highway Diesel Sulfur Control Requirements, January 18, 2001.

84. U.S. Department of Energy, *Review of the Component Design Report for the Petroleum Market Module*, memorandum prepared by J.L. Petersen (Washington, DC, June 1992).

85. U.S. Department of Energy, *Review of the Component Design Report for the Petroleum Market Module*, memorandum prepared by C.P. Shirkey (Washington, DC, June 1992).

86. Urbanchuk, J.M. 1998. Review of Alternative Ethanol Supply Curves Used in the Energy Information Administration's National Energy Modeling System.

87. Walsh, M. et al June 1997. Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price. Oak Ridge National Laboratory.

88. Wang, M. et al 1997. Fuel-Cycle Fossil Energy Use and Greenhouse Gas Emissions of Fuel Ethanol Produced from U.S. Midwest Corn.

89. Also see citations in Appendix A.

APPENDIX D

Model Abstract

APPENDIX D Model Abstract

D.1 Model Name:

Petroleum Market Model

D.2 Model Acronym:

PMM

D.3 Description:

The Petroleum Market Model is a simulation of the U.S. petroleum industry. It includes 12 domestic crude oil production regions, five refining centers with full processing representations and capacity expansion capability and gas plant liquid production, and nine marketing regions. The heart of the model is a linear programming optimization which ensures a rational economic simulation of decisions of petroleum sourcing, resource allocation, and the calculation of a marginal price basis for the products. Twenty-three refined products are manufactured, imported, and marketed. Ten of these products are specification blended, nine are recipe blended, and four are either unfinished products or by-product. Capacity limited transportation systems are included to represent existing intra-U.S. crude oil and product shipments (LPG, clean, dirty) via pipeline, marine tanker, barge, and truck/rail tankers. The export and import of crude oil and refined products is also simulated. All imports are purchased in accordance with import supply curves. Domestic manufacture of methanol is represented as though the processing plants are part of a refinery complex. Ethanol sources are treated as merchant plants. Transportation is allowed for ethanol shipments to the demand region terminals for splash blending.

The program is written in FORTRAN which includes callable subroutines allowing full communication with the LP portion of the model which is in the form of an MPS resident file.

D.4 Purpose of the Model:

The PMM models domestic petroleum refining activities, the marketing of petroleum products to consumption regions, the production of natural gas liquids in gas processing plants, and domestic methanol and MTBE production. The purpose of the PMM is to project petroleum product prices, refining activities, and movements of petroleum across United States' borders and among domestic regions. In addition, the model contains adequate structure and is sufficiently flexible to examine the impact of a wide

variety of petroleum-related issues and policy options. These capabilities allow for understanding of the petroleum refining and marketing industry as well as determine the effects of certain policies and regulations.

The PMM projects sources of supply for meeting petroleum product demand. The sources of supply include crude oil, both domestic and imported; other inputs including alcohols and ethers; natural gas plant liquids production; petroleum product imports; and refinery processing gain. In addition, the PMM estimates domestic refinery capacity expansion and fuel consumption. Product prices are estimated at the Census Division (CD) level and much of the refining activity information is at the Petroleum Administration for Defense District (PADD) level.

D.5 Most Recent Model Update:

November 2005

D.6 Part of Another Model?

The PMM is a component of the National Energy Modeling System (NEMS)

D.7 Model Interfaces:

The PMM receives information from the International, Natural Gas Transmission and Distribution, Oil and Gas Supply, Renewable Fuels, Electricity Market, Residential, Commercial, Industrial, and Transportation Models and delivers information to each of the models listed above plus the Macroeconomic Model.

D.8 Official Model Representative:

William Brown
Office of Integrated Analysis and Forecasting
Oil and Gas Division
(202) 586-8181

D.9 Documentation:

EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System (NEMS), February 2006. (DOE/EIA-M059).

D.10 Archive Media and Installation Manual

Archived as part of the NEMS *AEO2006* production runs.

D.11 Energy System Described:

Petroleum refining industry and refined products market.

D.12 Coverage:

Geographic: Twelve domestic crude oil production regions (East Coast, Gulf Coast, Mid-Continent, Permian Basin, Rocky Mountain, West Coast, Atlantic Offshore, Gulf Offshore, Pacific Offshore, Alaska South, Alaska North, Alaska Offshore); five refining regions (PADDs I-V); nine market regions, the Census divisions (New England, Mid Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, Pacific)

Time Unit/Frequency: Annual, 1995 through 2030

Products: LPG, conventional motor gasoline, conventional high oxygen motor gasoline, reformulated motor gasoline, reformulated high oxygen motor gasoline, M85, E85, jet fuel, distillate fuel oil, low-sulfur diesel, ultra-low sulfur diesel, low-sulfur residual fuel oil, high-sulfur residual fuel oil, petrochemical feedstocks, asphalt/road oil, marketable coke, still gas, "other" petroleum products, ethanol and biodiesel.

Refinery Processes: crude distillation, vacuum distillation, delayed coker, fluid coker, visbreaker, fluid catalytic cracker, thermal cracker, hydrocracker-dist, hydrocracker-resid, solvent deasphalter, resid desulfurizer, FCC feed hydrofiner, distillate HDS, naphtha hydrotreater, catalytic reformer-450 psi, catalytic reformer-200 psi, alkylation plant, catalytic polymerization, pen/hex isomerization, butane isomerization, etherification, butanes splitter, dimersol, butylene isomerization, total recycle isomerization, naphtha splitter, C2-C5 dehydrogenator, cyclar unit, hydrogen plant, sulfur plant, aromatics recovery plant, lube + wax plants, FCC gasoline splitter, gas/H2 splitter, stream transfers, fuel system, steam production, power generation, and petroleum coke gasification.

Crude Oil: Alaska low-sulfur light, Alaska mid-sulfur heavy, domestic low-sulfur light, domestic mid-sulfur heavy, domestic high-sulfur light, domestic high-sulfur heavy, domestic high-sulfur very heavy, imported low-sulfur light, imported mid-sulfur heavy, imported high-sulfur light, imported high-sulfur heavy, imported high-sulfur very heavy.

Transportation Modes: Jones Act dirty marine tanker, Jones Act clean marine tanker, LPG marine tanker, import tankers, clean barge, dirty barge, LPG pipeline, clean pipelines, dirty pipelines, rail/truck tankers. These cover all significant U.S. links.

D.13 Modeling Features:

Model Structure: FORTRAN callable subroutines which update the linear programming matrix, re-optimize, extract and post-process the solution results, update system variables, and produce reports.

Model Technique: Optimization of linear programming representation of refinery processing and transportation which relates the various economic parameters and structural capabilities with resource constraints to produce the required product at minimum cost, thereby producing the marginal product prices in a manner that accounts for the major factors applicable in a market economy.

Special Features: Choice of imports or domestic production of products is modeled, capacity expansion is determined endogenously, product prices include fixed and environmental costs, oxygenated and reformulated gasolines, and low-sulfur and ultra-low sulfur diesel fuels are explicitly modeled.

D.14 Non-DOE Input Sources:

Information Resources Inc. (IRI), WORLD model data, National Petroleum Council, ICF Resources, Oil and Gas Journal, U.S. EPA gasoline properties survey.

D.15 DOE Input Sources:

Forms:

EIA-14	Refiners' Monthly Cost Report
EIA-182	Domestic Crude Oil First Purchase
EIA-782A	Monthly Petroleum Product Sales
EIA-782B	Reseller/Retailer's Monthly Petroleum Product Sales
EIA-782C	Monthly Petroleum Products Sold into States for Consumption
EIA-759	Monthly Power Plant Report
EIA-810	Monthly Refinery Report
EIA-811	Monthly Bulk Terminal Report
EIA-812	Monthly Product Pipeline Report
EIA-813	Monthly Crude Oil Report
EIA-814	Monthly Imports
EIA-817	Monthly Tanker and Barge Movement

EIA-820	Annual Refinery Report
EIA-826	Monthly Electric Utility Sales
EIA-856	Monthly Foreign Crude Oil Acquisition
EIA-860B	Annual Nonutility Power Producer Report
FERC-423	Monthly Report of Cost and Quality of Fuels for Electric Plants

In addition to the above, information is obtained from several Energy Information Administration formal publications: *Petroleum Supply Annual*, *Petroleum Supply Monthly*, *Petroleum Marketing Annual*, *Petroleum Marketing Monthly*, *Fuel Oil and Kerosene Sales*, *Natural Gas Annual*, *Natural Gas Monthly*, *Annual Energy Review*, *Monthly Energy Review*, *State Energy Data Report*, *State Energy Price and Expenditure Report*.

D.16 Independent Expert Reviews Conducted:

Independent reviews of the PMM were conducted by:

A.S. Manne, ASM Consulting Services, July 1992

A.S. Manne, ASM Consulting Services, September 1992

N. Yamaguchi, Trans-Energy Research Associates, Inc., November 1997.

J. Urbanchuk, AUS Consultants, May 1998.

Ray Ory, independent consultant, June 2003

Terry Higgins, International Fuel Quality Center, June 2003

Fred Joutz and Inderjit Kundra, George Washington University and Statistics and Methods Group of EIA, December 2003

Julian Silk, Robert P. Trost, Michael Ye, and Inderjit Kundra, Statistics and Methods Group of EIA, November 2005

D.17 Status of Evaluation Efforts by Sponsor:

None.

APPENDIX E

Data Quality

APPENDIX E. Data Quality

E.1 Quality of Distribution Cost Data

Costs relating to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products are estimated as the average annual difference between retail and wholesale prices over the years 1990 through 2000.[1] The differences are based on **wholesale prices** in the producing Census Division and **end-use prices** (which do not include taxes) in the consuming Census Division. See Appendix F for a discussion of programs and input files used in estimating these markups.

Annual **wholesale prices** for all petroleum products are aggregated from state-level prices from the EIA-782A. The estimation and reliability of the EIA-782A data is discussed in the *Petroleum Marketing Annual 2004 (http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/historical /2004/pma_2004.html* . See Explanatory Notes for inputs and sources.

With the exception of gasoline, non-utility distillate fuel, and jet fuel, **sectoral end-user prices** through 2001 are aggregated from prices from *State Energy Data 2001: Prices (SEDP) (http://www.eia.doe.gov/emeu/states/_states.html)* . The methodology behind these state-level sectoral prices is discussed in the Technical notes section *(http://www.eia.doe.gov/emeu/states/sep_prices/notes/pr_petrol.pdf)*.

Gasoline, jet fuel, and non-utility distillate prices are estimated as weighted averages using end-user prices from EIA-782A and sectorial consumption from the *State Energy Data 2001: Consumption (SEDC) (http://www.eia.doe.gov/emeu/states/_states.html).*

Due to a lag in the publication of the *SEDP* data, end-use price estimates for 2001-2004 are calculated using the same data series and methodology described in *SEDP*. The *SEDP* methodology uses prices from EIA-782A, FERC-423, EIA-759, and weights them with most recent consumption volumes from *SEDC*. Refer to *SEDC* for a discussion of the reliability of consumption data *(http://eia.doe.gov/pub/state.data/pdf/petrol.pdf*, May 2001). Years 2005 and 2006 are estimated by applying the percent change of national product prices as reported in the September 2005 Short Term Energy Outlook (STEO) to each 2001 sectorial price.

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[1]Transportation markups for kerosene are based on the difference between end-user kerosene prices and wholesale distillate prices.

Table E1. Sources of Markup Inputs

Products	Sectors	Data Series Inputs
Distillate	CM, IN, RS	EIA-782A, SEDC
Jet Fuel	TR	EIA-782A, SEDC
Low Sulfur Diesel Fuel	TR	EIA-782A, SEDC
Motor Gasoline	CM, IN, TR	EIA-782A, SEDC
Asphalt and Road Oil	IN	SEDP, EIA-782A, SEDC
Kerosene	CM, IN, RS	SEDP, EIA-782A, SEDC
Liquified Petroleum Gases	CM, IN, RS, TR	SEDP, EIA-782A, SEDC
Low Sulfur Residual Fuel	CM, IN	SEDP, EIA-782A, SEDC
High Sulfur Residual Fuel	TR	SEDP, EIA-782A, SEDC
Distillate	EU	SEDP, EIA-759, FERC-423
Low Sulfur Residual Fuel	EU	SEDP, EIA-759, FERC-423
High Sulfur Residual Fuel	EU	SEDP, EIA-759, FERC-423

E.2 Quality of Tax Data

In the PMM, State and Federal taxes are added to the prices of gasoline, distillate fuel, liquefied petroleum gas (LPG), jet fuel, ethanol, and methanol in the transportation sector. State taxes are assumed to keep pace with inflation (held constant in real terms) while Federal taxes are held at current nominal levels (deflated in each forecast year).[2] The Federal tax assumption reflects the overall forecast assumption of current laws and legislation. The assumption that State taxes will increase at the rate of inflation reflects an implied need for additional highway revenues as driving increases. An additional 1 percent per gallon of gasoline price is added to the State gasoline taxes to approximate local taxes.

The State taxes are added as Census Division weighted averages which are based on the most recently-available State taxes. State taxes for jet fuel are derived from unpublished data collected by the Petroleum Marketing Division of EIA, while state taxes for ethanol are taken from average prices reported in *Oxy Fuel News* (published by Hart Energy Publishing, LP). State and Federal taxes for gasoline, transportation distillate, and LPGs are based on data from the Federal Highway Administration, but are modified to include other known changes to State taxes. The quality of the State level tax data is unknown but deemed reliable. The local tax estimate of 1 percent per gallon of gasoline price is reasonable given that a comparison of two EIA data series, one including local taxes and one not, revealed a gasoline price difference of 1.6 cents-per-gallon.[3]   Federal taxes, which were adjusted in January of 2001, are widely published and deemed highly reliable.

See Appendix F for a description of programs and input files used in the calculation of historical taxes and the estimation of taxes used in the price projections.

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[2]Refer to Stacy MacIntyre, *Motor Fuels Tax Trends and Assumptions*, Issues in Midterm Analysis and Forecasting 1998, DOE/EIA-0607(98), (Washington, D.C., July 1998).

[3]Macro International, Inc., *EIA-888 and EIA-878 Data Comparisons and Performance Measures*, Third Quarter 1997 (Washington, D.C., December 15, 1997).

E.3 PMM Critical Variables

The PMM contains numerous variables and parameters. Some variables have greater impact on model results than others. The following is a list of variables that we believe has a high degree of influence on PMM results. It is provided to help users understand the critical factors affecting the PMM.

- World oil price
- Product demands
- Imported crude supply curves
- Imported product supply curves
- Domestic crude production
- Prices and available supplies of methanol, ethanol, MTBE, and other ethers
- Investment cost for capacity expansion
- Market shares for gasoline and distillate types
- NGL supply volumes

Most of these variables are provided by other models in the NEMS system. Ethanol supply and prices are provided by the Ethanol Supply Model, a sub-module of the PMM, documented in Appendix I. The investment cost and market share data are developed offline and read in to the PMM.

APPENDIX F. Estimation Methodologies

F.1 Refinery Investment Recovery Thresholds

The threshold for expansion investment decisions is represented by the process plant cost function (PCF). The PCF considers actual cash flows associated with the operation of the individual process plants within the refinery, as well as cash flows associated with capital for the construction of new plants. It includes terms for capital-related financial charges (CFC), fixed operating costs (FOC), and other variable operating costs (OVC):

$$PCF \ = \ \Sigma_i (\ CFC_i + FOC_i \ + \ OVC_i \ ) \tag{1}$$

where

$i =$ individual process plants that make up the petroleum refinery, such as the atmospheric crude distillation unit, fluid catalytic cracking unit, etc.

However, since the OVC_i for each processing unit are represented as a separate term in the PMM LP objective function, only the sum of the FOC_i and CFC_i is included as the coefficient in the objective function row corresponding to the unit expansion vectors (E(r)(uns)INV and L(r)(uns)BLD, respectively) in the PMM. The methodologies used to calculate the capital-related financial charges and the fixed operating costs are presented below.

Capital-Related Financial Charges (CFC)

The CFC equation includes an annual capital recovery charge (ACR) minus a depreciation tax credit (DTC):

$$CFC_i \ = \ ACR_i \ - \ DTC_i \tag{2}$$

A discounted cash flow calculation is generally used to determine the annual capital charge for any given plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital (COC), which includes equity (cost of equity, COE) and interest payments on any loans or other debt instruments used as part of capital project financing (cost of debt, COD). The depreciation of capital equipment is used for the purpose of determining the depreciation tax credit (DTC). Both the ACR and DTC are estimated on an after-tax basis.

Since the PMM and other energy forecasting models employ "notional" representations of U.S. petroleum refineries involving aggregation of data for many individual refineries, the cost estimating algorithm has been simplified while still capturing all the factors and costs refiners must consider when adding a new processing unit. The methodology draws upon the National Petroleum Council (NPC) study[1], and other

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[1] National Petroleum Council, *U.S. Petroleum refining – Meeting Requirements for Cleaner Fuels and Refineries*, Washington D.C., August 1993.

sources[2]. Some of the steps for the cost estimate are conducted exogenous to the NEMS (Step 0 below),
either by the analyst in preparing the input data or during input data preprocessing, such as the estimate for
the inside battery-limit (ISBL) field cost of the process unit. The individual steps in the plant capital cost
estimation algorithm are:

  0)   Estimation of the ISBL field cost

  1)   Estimation of the ISBL field cost for different refinery locations

  2)   Estimation of the outside battery-limit (OSBL) field cost and the total field cost

  3)   Estimation of total project cost

  4)   Estimation of capital-related financial charges

  5)   Convert capital-related charges to a "per-day," "per-capacity" basis

Step 0 may involve several adjustments which must be made prior to input into the PMM. The remaining
steps 1-4 are performed within the PMM.

Step 0 - Estimation of ISBL Field Cost

The inside battery limits (ISBL) field costs include the direct cost such as major equipment, bulk materials,
direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The
ISBL investment cost and labor costs for most of the processing unit types modeled were initially obtained
from a study by Bonner and Moore Associates (BMA),[3] and updated annually with revised estimates from
EnSys Energy and Systems, Inc. (EnSys). The data for typical unit sizes and stream factors, as well as
supplementary investment and labor, were obtained from the World Oil Refining, Logistics, and
Distribution (WORLD) model[4]. The data used by the PMM currently represent process plants sited at a
generic U.S. Gulf Coast (PADD III) location, and are in year 2000 dollars. (The latest EnSys data were
expressed in year 2000 dollars.)

Step 1 - Year-Dollar and Location Adjustment to ISBL Field Costs

Before the PMM can utilize the ISBL investment cost data, it must convert the raw information via the
following steps:

  a)   Adjust the ISBL field costs and labor costs for each processing unit (j) from 2000 dollars,
        first to the year-dollar (rptyr) reported by NEMS for *AEO2006*, which is in 2004 dollars,
        using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type
        price indices provided by the NEMS Macroeconomic Activity Model are used to convert

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[2]J.H. Gary and G.E. Handwerk, *Petroleum Refining: Technology and Economics,* 4th edition (New York: Marcel Dekker, 2001),
Chapters 17 and 18.

[3]Bonner & Moore Associates, Inc., *A Capital Expansion Methodology Review of the Department of Energy's Petroleum Market
Model*, prepared for the United States Department of Energy, Contract No. EI-94-25066 (Houston, TX, July 1994).

[4]EnSys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management prepared for the
United States Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, D.C., September 1992).

from report-year dollars to 1987 year dollars used internally by the NEMS.

b)   Convert the ISBL field costs in 1987 dollars for each processing unit (j) from a PADD III (Gulf Coast) basis (BM_ISBL$_j$) to costs of the same processing unit for other PADD regions (RISBL$_j$) via location multipliers (INVLOC$_l$) . The location multipliers represent differences in material costs between the various PADD regions.

$$RISBL_j \; = \; BM\_ISBL_j \; * \; INVLOC_l \; / \; 1000 \qquad\qquad (3)$$

where

RISBL$_j$ =   ISBL costs for processing unit j in refining region (PADD) l, in million 1987 dollars (MM 87$)

BM_ISBL$_j$ =   ISBL costs for processing unit j in PADD III, in thousand 1987 dollars (M 87$)

INVLOC$_l$ =   Location multiplier for refining region l

Location multipliers for refinery construction were developed on a PADD basis using the most recent data available from the U.S. Bureau of Labor Statistics (BLS)[5] and the EIA[6]. The development of these multipliers and assumed values for other factors is described elsewhere[7]. The recommended location multipliers for refinery construction are given below:

Table F1. Location Multipliers for Refinery Construction

Location	Construction Location Multiplier
PADD I – U.S. East coast	1.50
PADD II – U.S. Midwest	1.29
PADD III – U.S. Gulf Coast	1.00
PADD IV – U.S. Rocky Mountain	1.40
PADD V – U.S. West Coast	1.48

Step 2 - Estimation of OSBL Cost and Total Field Cost

The outside battery-limit (OSBL) costs include the cost of cooling water, steam and electric power generation and distribution, fuel oil and fuel gas facilities, water supply, etc. The total field cost (FDC) is the sum of the ISBL and OSBL field costs. The OSBL field cost is estimated as a fraction (OSBLFAC) of the ISBL costs. Thus, the resulting FDC equation is:

$$RFDC_j = (1. + OSBLFAC) * RISBL_j \qquad (MM \; 87\$) \qquad\qquad (4)$$

[5] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at *www.bls.gov/bls/blswage.htm*.
[6] Refinery Capacity Data, U.S. Department of Energy, Energy Information Administration, available on the web at *www.eia.doe.gov/oil_gas/petroleum/data_ publications/refinery_capacity_data/refcapacity.html*.
[7] *A General Cost Estimating Methodology for New Petroleum Refinery Process Capacity,* Appendix D, prepared for the U.S. Department of Energy, National Energy Technology Laboratory, and Energy Information Administration by John Marano, Ph.D., September 2004.

A default value of 0.45 is assumed by the PMM for the OSBL cost factor.

Step 3 – Estimation of Total Project Cost

The total project investment (TPI) is the sum of the total field cost (Eq. 4) and other one-time costs (OTC):

$$RTPI_j = RFDC_j + ROTC_j \qquad \text{(MM87\$)} \qquad (5)$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital (WC). The OTC's are estimated as a function of total field costs (FDC), using cost factors (OTCFAC). The corresponding equations are presented below.

$$OTCFAC = PCTENV + PCTCNTG + PCTLND + PCTSPECL + PCTWC \qquad (6)$$

where

PCTENV	= 0.10	Home, office, contractor fee
PCTCNTG	= 0.05	Contractor & owner contingency
PCTLND	= 0.00	Land (assuming expansion only at existing refinery)
PCTSPECL	= 0.05	Prepaid royalties, license, start-up costs
PCTWC	= 0.10	Working capital
thus, OTCFAC	= 0.30	

and

$$ROTC_j = OTCFAC * RFDC_j \qquad \text{(MM 87\$)} \qquad (7)$$

The TPI given above represents the total project cost for "overnight construction.." The TPI at project completion and startup will be discussed in Step 4 below.

Closely related to the total project investment are the fixed capital investment (FCI) and total depreciable investment (TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs (discussed later). A default value of 0.10 is assumed for the WC factor:

$$WRKCAP = PCTWC * RFDC_j \qquad \text{(MM 87\$)} \qquad (8)$$

thus,

$$RFCI_j = RTPI_j - WRKCAP \qquad \text{(MM 87\$)} \qquad (9)$$

The total depreciable investment is equal to the total project investment less the cost of land, interest during construction and working capital (as discussed in Step 4 below). For construction at an existing refinery site through expansion, as most likely the case in the United States, the cost of land can be assumed to be zero, and interests during construction are considered implicitly in the calculation of the capital charge factor (Step 4); thus, total depreciable investment is assumed to be approximately equal to fixed capital investment:

$$RTDI_j = RFCI_j \qquad\qquad\qquad (MM\ 87\$) \qquad\qquad\qquad (10)$$

Step 4 - Estimation of Capital-Related Financial Charges

For the purpose of determining the economic viability of expanding refinery processing capacity, capital-related financial charges (CFC), which consist of an annual capital recovery charge (ACR) and a depreciation tax credit (DTC), must be estimated from the total project investment (TPI). The ACR is based on the cost of capital (COC) for the corporation that owns the refinery where the project is located. It is assumed that projects will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders. Therefore, the after-tax weighted average cost of capital is an appropriate discount rate for evaluating investment opportunities.

> a)   Cost of Capital

The cost of capital (COC) is the weighted average of the cost of equity (COE) and cost of debt (COD). The COE represents an implied opportunity of financial return to the corporation's stockholders in the form of dividend payments and stock price appreciation. The COD is the after-tax interest rate, which a company would pay for new, long-term borrowing. In general, the required rate of return for equity investors is much higher than the required rate of return for debt investors (creditors) since the holder of common stock (equity investors) accepts all the risks involved in business ownership. The COC is related to COE and COD as follows:

$$COC = x_{eq} \times COE + x_{debt} \times COD(at) \qquad\qquad\qquad (11)$$

and,

$$COD(at) = (1 - T_{eff,l}) \times COD(bt) \qquad\qquad\qquad (12)$$

where

x_{eq}, x_{debt} =	Fractions of equity and debt financing, respectively ($x_{debt} = 1 - x_{eq}$)
$T_{eff,l}$ =	Effective corporate income tax rate; "l" is for refining region index where all state taxes in that region are averaged to represent a single value.
at, bt =	Indices for after- and before-taxes, respectively

Based on a review of annual financial reports of refining companies or their parent companies, the relative fraction of equity and debt used in the model is set to the capacity-weighted average determined for 2002 ($x_{eq} = 0.60$ and $x_{debt} = 0.40$). Also, T_{eff} is related to the federal tax rate T_{fed} (FTAXRAT in the PMM) and state tax rate T_{state} (STAXRAT in the PMM, which is location dependent) as follows:

$$T_{eff,l} = T_{state,l} + T_{fed} \times (1 - T_{state,l})$$
$$= T_{fed} + T_{state,l} - T_{fed} \times T_{state,l,} \tag{13}$$

Average state and federal income tax rates were developed on a PADD basis using the most recent tax information available as of Jan. 1, 2004[8]. PADD averages were weighted based on the crude oil processing capacity within the states making up each PADD. The resulting state and federal tax rates used in the model are:

Table F2. State and Federal Corporate Income Tax Rates

Location	State	Federal
PADD I – U.S. East coast	9.32%	35%
PADD II – U.S. Midwest	7.38%	35%
PADD III – U.S. Gulf Coast	3.32%	35%
PADD IV – U.S. Rocky Mountain	4.21%	35%
PADD V – U.S. West Coast	6.76%	35%

The pre-tax cost of debt (COD(bt)) will vary based on the proportions of short-term loans and bonds. A Baa average corporate bond rate (MC_RMCORPBAA from the NEMS Macroeconomic Activity Model) is used for COD(bt).

The expected opportunity cost, or cost of equity (COE), for stockholders should be comparable to what could be realized from alternative investments of similar risk. The Capital Asset Pricing Model (CAPM) is used to compute a cost of equity[9], which is an implied investor's opportunity cost or the required rate of return of any risky investment. The model is:

$$COE = RFR + \beta \times EMRP \tag{14}$$

The model requires three variables be specified: RFR, a "risk-free" rate; EMRP, an expected market risk premium; and β, a systematic risk coefficient relative to the stock market (referred to as the "equity beta"). In the model, the risk-free rate is based on 10-year Treasury note rates (MC_RMTCM10Y, provided by the NEMS Macroeconomic Activity Model). The EMRP and β (BEQ, in model) are assumed to be constant. Thus, the EMRP is assumed at 6.75 percent (7% for high risk) based on the expected return on market over the rate of a 10-year Treasury note (risk-free rate); and, the β is set based on the risk level of the processing unit investment (for average risk, β = 0.8; for high risk, β = 1.25).

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[8] State Coporate Income Tax Rates, available on the web at: www.taxfoundation.org/corporateincometaxrates.html, and at www.taxadmin.org/fta/rate/corp_inc.html.

[9] The **capital asset pricing model** (CAPM) was introduced by Treynor (1961), Sharpe (1964) and Lintner (1965). It extended portfolio theory to introduce the notions of systematic and specific risk. More description of the model can be found at: http://www.riskglossary.com/articles/capital_asset_pricing_model.htm

b)   Annual Capital Recovery

The annual capital recovery (ACR) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated in Step 3 is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$TPI(startup) \;=\; F_v(COC,N_{con}) \times LC + F_{v,n}(COC,N_{con}) \times (\; TPI(ONC) - LC - WC \;) + WC \tag{15}$$

where

$F_v =$ Future-value compounding factor for an instantaneous payment made n years before the startup year

$F_{v,n} =$ Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup (N_{con} years), and the compounding rate used is the cost of capital (COC). The formulae for computing each of the discrete compounding factors are:

$$F_v(COC,N_{con}) \quad = (1. + COC)** N_{con} \tag{16}$$

$$F_{v,n}(COC,N_{con}) \;= (\; \underset{k=1,\,N_{con}}{\Sigma} (\; (1.+ COC)**k)\;) \;/\; N_{con} \tag{17}$$

The recoverable investment (RCI) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (SV) of the used equipment:

$$RCI \;=\; LC + WC + SV \qquad\qquad \text{(MM87\$)} \tag{18}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI(startup) \;=\; TPI(startup) \; - P_v(COC,N_{asset}) \times RCI \quad \text{(MM87\$\}} \tag{19}$$

Where

$P_v =$ Present-value discounting factor for an instantaneous payment made n years (project life) in the future. The present-value factor is a function of the number of discounting periods (n), and the interest rate (r) used for discounting. In this case, (n) equals the asset's economic life in years N_{asset}, and the discounting rate is the

cost of capital COC:

$$P_v(COC,N_{asset}) \ = 1. \, / \, ((1.+COC)^{**} \, N_{asset}) \qquad \text{(MM87\$)} \qquad\qquad (20)$$

If the cost of land is assumed to be zero, and the salvage value is equal to dismantling costs, then the PVI(startup) can be reduced to:

$$PVI(startup) \ = \ F_{v,n}(COC,N_{con}) \times FCI \ + \ (\ 1 - P_v(COC,N_{asset}) \times WC\ ) \qquad\qquad (21)$$

Thus, the annual capital recovery (ACR) is given by:

$$ACR(at) \ = \ A_v\,(COC,N_{asset}) \times PVI(startup) \qquad \text{(MM87\$/yr)} \qquad\qquad (22)$$

where

    $A_v =$ uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future, and (at) signifies that the required annual capital recovery is on an after-tax basis. The uniform-value factor is a function of the number of periods (n), and the interest rate (r), where (n) equals the asset's economic life in years N_{asset}, and the discounting rate is the cost of capital COC, as defined by:

$$A_v\,(COC,N_{asset}) \ = (COC \,{*}((1.+COC)^{**}\,N_{asset})) \ \, / \ (((1.+ COC)^{**}\,N_{asset}) \,{-}1.) \qquad (23)$$

A construction period of 2 years and asset life of 15 years are assumed for construction of a new plant within an existing refinery.

c)   <u>Depreciation Tax Credit & Capital-Related Financial Charges</u>

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations (and used in the PMM) is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$PVD_{DPM}(startup) \ = \ P_{v,DPM}(COC,N_{tax}) \times TDI \qquad \text{(MM87\$)} \qquad\qquad (24)$$

$$DTC(at) \ = \ A_v\,(COC,N_{asset}) \times T_{eff} \ \times PVD_{DPM}(startup) \qquad \text{(MM87\$/yr)} \qquad\qquad (25)$$

where

    $P_{v,DPM} =$ Present-value discounting factor for depreciation, which is a function of the number of discounting periods (n), and the interest rate (r)

    $A_v =$ is the uniform-value leveling factor

    $T_{eff} =$ Effective combined income tax rate

    at $=$ Signifies the depreciation tax credit on an after-tax basis.

In this case, (n) equals the tax life in years N_{tax}, and (r) equals the cost of capital COC. The subscript DPM signifies the depreciation method used (i.e., straight-line method). If the tax life N_{tax} is assumed to be equal to the asset life N_{asset}, then the leveled depreciation tax credit (DTC) can be represented as follows:

$$DTC(at) \ = \ T_{eff} \times TDI \ / \ N_{asset} \qquad (\text{MM87\$/yr}, \text{DPM} = \text{SRL}, N_{tax} = N_{asset}) \qquad (26)$$

Finally, the capital-related financial charges (CFC) are set equal to the ACR less the DTC, after taxes (at) and before taxes (bt):

$$CFC(at) \ = \ ACR(at) \ - \ DTC(at) \qquad (\text{MM87\$/yr}) \qquad (27)$$

and,

$$CFC(bt) \ = \ CFC(at) \ / \ (1 - T_{eff}) \qquad (\text{MM87\$/yr}) \qquad (28)$$

Step 5 - Convert Fixed Operating Costs to a "per-day," "per-capacity" Basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-barrel basis. It is the before-tax CFC that is included in the process plant cost function (PCF) presented in equation (1) above.

Refinery Unit Fixed Operating Costs

Fixed operating costs (FOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other refinery overhead. These components can be factored from either the operating labor requirement or the capital cost. The accuracy of this type of estimate should be within ±50 percent.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

    0)   Estimation of the annual cost of direct operating labor
    1)   Year-dollar and location adjustment for operating labor costs (OLC)
    2)   Estimation of total labor-related operating costs (LRC)
    3)   Estimation of capital-related operating costs (CRC)
    4)   Convert fixed operating costs to a "per-barrel" basis

Step 0 involves several adjustments which must be made prior to input into the PMM; steps 1-4 are performed within the PMM.

Step 0 – Estimation of Direct Labor Costs

Direct labor costs are reported based on a given processing unit size. The operating labor cost data for most of the processing unit types modeled in the PMM were initially obtained from a study by Bonner and Moore Associates (BMA), and updated annually with revised estimates from EnSys. The actual data were obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model.[10] The data used by the PMM currently represent process plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in year 2000 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs

Before the PMM can utilize the labor cost data, it must convert the raw information via the following steps:

a) Adjust the labor costs for each processing unit (j) from 2000 dollars, first to the year-dollar (rptyr) reported by NEMS for *AEO2006*, which is in 2004 dollars, using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS.

b) Convert the 1987 operating labor costs for each processing unit (j) from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional (l) location factors. The location multiplier (LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$RLABOR_{j,i} \; = \; BM\_LABOR_j \; * \; LABORLOC_i \qquad \text{(87\$/calendar day)} \qquad \text{(29)}$$

Location multipliers for refinery operating labor were developed on a PADD basis using the most recent data available from the U.S. Bureau of Labor Statistics (BLS)[11] and the EIA.[12] The recommended location multipliers for refinery construction are given below:

Table F3. Location Multipliers for Refinery Operating Labor

Location	Operating Labor Multiplier
PADD I – U.S. East coast	1.11
PADD II – U.S. Midwest	0.98
PADD III – U.S. Gulf Coast	1.00
PADD IV – U.S. Rocky Mountain	1.07
PADD V – U.S. West Coast	1.06

Step 2 - Estimation of Labor-Related Fixed Operating Costs

Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the refinery, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (LRC) can be factored from the direct operating labor cost (OLC). This relationship is expressed by:

$$LRC = M_{LRC} * OLC \qquad \text{(M87\$/yr)} \qquad (30)$$

where

M_{LRC} = Aggregate of LRC cost multipliers relating the LRC to the cost of direct operating labor cost (OLC). Default values of 0.55 for supervisory/staff and 0.39 for benefits/overhead are combined in the following set of component equations to produce the aggregate multiplier of 2.15.

$$
\begin{aligned}
&\text{FXOC\_STAFF} = 0.55*\text{OLC} &&\text{<supervisory/staff>} \\
&\text{FXOC\_OH} \quad = 0.39*\text{FXOC\_STAFF} &&\text{<benefits/OH>} \\
&\text{RLABOR} \quad = \text{OLC} &&\text{<labor>}
\end{aligned}
$$

$$
\begin{aligned}
LRC \quad &= FXOC\_STAFF + FXOC\_OH + RLABOR \\
&= (0.55*OLC) + 0.39*(0.55*OLC) + OLC \\
&= 2.15 * OLC \qquad \text{(M87\$/yr)} \qquad (31)
\end{aligned}
$$

Step 3 - Estimation of Capital-Related Fixed Operating Costs

Capital–related fixed operating costs (CRC) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (FCI). This relationship is expressed by:

$$CRC = M_{CRC} * FCI \qquad \text{(MM87\$/yr)} \qquad (32)$$

where

M_{CRC} = Sum of CRC cost multipliers.

The multipliers used in the PMM are defined in the table below:

Table F4. Capital-Related Fixed Operating Cost Multipliers

Yearly Insurance	0.005
Local Tax Rate	0.01
Yearly Maintenance	0.03
Yearly Supplies, Overhead, Etc.	0.005

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis

On a "per-capacity" basis, the FOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

F.2 Gas Plant Models

The gas plant models for each PADD are recorded on a spreadsheet maintained within EIA by the Oil and Gas Division. These models require gas plant wet gas volumes as input. In order to accommodate the information available and permit gas plant activity to be driven by dry natural gas demand, factors are applied to dry gas production volumes to calculate imputed volumes of processed wet gas. The PMM uses California gas processing plants as a proxy for PADD V. Although Alaska produces and processes a considerable volume of natural gas, it is nearly all re-injected with some NGL dumped into the crude pipeline with the exception of modest volumes of southern Alaska production. The southern Alaska production has a local NGL market with much of the dry gas shipped to Japan as LNG. In any case, the PADD V refinery industry is virtually unaffected by Alaska NGL production, and California serves as a proxy for the district. Thus, the PMM aggregate gas plant for PADD V includes California only.

Gas residue volumes are not available to the PMM but total dry gas volumes by PADD are. For *AEO2006*, wet gas volumes arising from Coal Bed Methane (CBM) and shale gas are excluded from the wet gas estimate calculation since these gas types contain little or no liquids content and there is no economic incentive to process them in a gas plant. This information is contained in the NEMS common block region. Specifically, the total dry gas volumes are available in:

Common block:	NGTDMOUT
Variable matrix:	PRNG_PADD(PADD,YEAR), BCF
Description:	Total dry gas produced including plant fuel and lease fuel (P&L) for PADD 'PADD' in year 'YEAR' excluding Alaska.

Each dry gas PADD volume is multiplied by a factor to obtain an estimate of the corresponding wet gas that is processed by the gas plants; i.e. the total dry gas volumes are multiplied by the ratio of processed wet gas to total dry gas production. The conversion ratios are derived from the average of the most recent five years of data[13] with the analysis maintained offline. It should be noted that Coal Bed Methane does not contain any gas liquids; hence, the volume of Coal Bed Methane gas is excluded when grossing up the dry gas volumes to arrive at the wet gas volumes. The five factors (Table GASCAP) are contained in file nrfplant.dat as shown in Table F5.

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[13]Energy Information Administration, *Natural Gas Annual* for years 1992-2002, DOE/EIA,

Table F5. Total Dry Gas Multiplier

PADD	Factor
I	0.3343
II	0.6807
III	0.7397
IV	0.7708
V (CA)	0.7209

The multiplier for PADD I is relatively low because little of the modest PADD I gas production is processed for liquids extraction beyond field decontamination.

The basic model structure for the gas plant was originally devised from the Pace Consultants annual petrochemical report[14] and has been modified over the years as gas markets have evolved. Liquids (NGL) extraction data have been calculated by averaging actual liquid extraction volumes from the 5-year period 1998 - 2002[15]. The data are contained in Table GASPLT in file nrfplant.dat, as shown in Table F6 for illustrative purposes.

Table F6. Gas Plant Model Liquid Component Yields
(M Bbls per MMcf)

	PADD I	PADD II	PADD III	PADD IV	PADD V
Ethane	23.40	20.77	18.12	20.80	0.19
Propane	32.61	20.38	13.01	17.22	14.59
Iso Butane	4.06	3.89	5.25	3.45	6.10
Normal Butane	11.50	6.62	2.85	6.71	7.15
Natural Gasoline	9.33	8.02	7.12	8.99	14.20

Both ethane and propane rejection can occur at the gas plant. This represents the quantity of these liquids that remain in the dry gas. A processing credit for each barrel rejected is linked in the objective function row. Propane rejection in each PADD is limited using an upper bound on the regional rejection variable [G(r)SC3CC1]. For *AEO2006*, ethane rejection in each PADD [G(r)SC2CC1] is limited to 25 percent

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[14]Pace Petrochemical Service, *Annual Issue*, (Houston, TX, September 1989).

[15]Energy Information Administration, *Petroleum Supply Annual 1992-2002*, DOE/EIA, and similarly, the *Natural Gas Annual* for years 1992-2002.

(based on historical averages) of the total ethane available for extraction. An additional restriction is put on the amount of ethane (NGL) allowed to transfer into the LPG stream. This too is limited to 25 percent of the total ethane available for extraction from the wet gas.

F.3 Chemical Industry Demand for Methanol

The PMM incorporates methanol plant models in each PADD representing all operating methanol capacity in the U.S. Given the diverse and competing uses for methanol in both the refining and petrochemical industries, U.S. chemical industry demand (demand other than for MTBE/TAME feedstock and neat fuel) is a required input to gauge market supply pressures. The chemical industry demand requirement (Tables DEMMET and PRDDMDME) is entered in files demand.dat and qdcrdcf.txt, respectively. Chemical Market Associates, Inc. (CMAI) makes long range forecasts of demand for methanol [16] by the chemical industry. This forecast is outlined in Table F7.

Table F7. Chemical Industry Demand for Methanol

Year	Demand (Mbbl/d)	Year	Demand (Mbbl/d)
1990	77.7	2011	140.7
1991	73.1	2012	143.7
1992	80.0	2013	146.3
1993	83.9	2014	149.1
1994	87.7	2015	151.9
1995	90.2	2016	155.7
1996	94.6	2017	158.9
1997	100.2	2018	162.4
1998	108.8	2019	165.7
1999	111.0	2020	169.4
2000	118.3	2021	173.0
2001	110.6	2022	176.9
2002	112.7	2023	180.7
2003	114.1	2024	184.9
2004	117.3	2025	189.0
2005	120.8	2026	193.3
2006	124.1	2027	197.8
2007	127.7	2028	202.3
2008	131.2	2029	207.0
2009	134.4	2030	211.8
2010	137.3		

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[16]CMAI, (Houston, TX), United States Methanol Chemicals Demand, (January 2004), updated July 2005.

The methanol plant model in each PADD is represented by a single column activity that consumes natural gas and produces methanol. Two additional transportation activities allow the methanol produced to be transported to the refining region for production of MTBE/TAME and/or splash blending in gasoline or sent to meet the national demand for methanol by chemical plants. Given the mounting phase-out of MTBE as a gasoline blending component, methanol is becoming a less-sensitive refinery driver component within the PMM modeling structure.

Methanol plant capacity (Table MOHCAP) is updated periodically for the five PADDs in file nrfplant.dat using *Chemical Market Reporter* and other industry trade references for establishing current operating capacity. The model allows capacity expansion of methanol plants if ever needed. However, from a practical standpoint, an abundance of mothballed plants would likely be reopened rather than implementing new construction since nearly half U.S. methanol production capacity has been closed down since the late 1990s. In mid-2005, 75 percent of methanol production capacity was shut down and that figure was estimated to increase to 80 percent by the end of the year.

F.4 Estimation of Distribution Costs

Costs related to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products except gasoline are estimated as the average annual difference between retail and wholesale prices. Due to an observable market shift before and after 1990 (due to the CAAA of 1990), the transportation markups for all products except gasoline are estimated based on data between 1990 and 2001. Due to the requirement for oxygenated gasoline beginning in October of 1992, gasoline markups are estimated with data beginning in 1993. The differences are based on wholesale prices in the producing Census division and end-use prices (which do not include taxes) in the consuming Census division. Wholesale prices are aggregated from State-level prices from the EIA-782A. Sectoral end-user prices are aggregated from State-level prices from the *State Energy Data 2000: Prices (SEDP)* Report . End-use prices after 2000 are estimated according to the SEPER's methodology. Computer programs and data files used to estimate transportation markups are discussed below.

Data-Reading Programs

Database: **SEDS_SEPERS.mdb**

Input Files :   pr_pet_all_price.csv
                        use_pet_all_btu.csv

This database reads State-level prices by sector from SEPER data query provided by EIA's Julia Hutchins of Office of Energy Markets and End-Use (EMEU). To import new data use the Acess import utility with the Specification SEDS BTU Data Import Specification for the Volume file and SEPER Price Import Specification for the Price file. These files include the following data series from 1960-2001:

ARICB	ARICD	ARICV	AVACB	AVACD
AVACV	DFACB	DFACD	DFACV	DFCCB
DFCCD	DFCCV	DFEUB	DFEUD	DFEUV
DFICD	DFICV	DFISB	DFRCB	DFRCD
DFRCV	FNICB	FNICD	FNICV	FOICB
FOICD	FOICV	FSICB	FSICD	FSICV
JFACB	JFACD	JFACV	JFEUB	JFEUD
JFEUV	KSCCB	KSCCD	KSCCD	KSICB
KSICD	KSICV	KSRCB	KSRCD	KSRCV
LGACB	LGACD	LGACV	LGCCB	LGCCD
LGCCV	LGICD	LGICV	LGISB	LGRCB
LGRCD	LGRCV	LUACB	LUACD	LUACV
LUICB	LUICD	LUICV	MGACB	MGACD
MGACV	MGCCB	MGCCD	MGCCV	MGICB
MGICD	MGICV	MSICB	MSICD	MSICV
PCEUB	PCEUD	PCEUV	PCICD	PCICV
PCISB	RFACB	RFACD	RFACV	RFCCB
RFCCD	RFCCV	RFEUB	RFEUD	RFEUV
RFICD	RFICV	RFISB	SNICB	SNICD
SNICV	WXICB	WXICD	WXICV	

The Five letter code corresponds to the following information.

Data Identification Codes	
Characters	**Identity**
1 and 2	represent an Energy Source (Fuel)
3 and 4	represent an Energy Consumption End-Use Sector (Sector)
5	represents a Type of Data (Type)

Energy Source (Characters 1 and 2)	
Code	**Name**
AR	asphalt and road oil
AV	aviation gasoline
DF	distillate fuel
FN	petrochemical feedstocks naphtha less than 401 degrees F.
FO	petrochemical feedstocks other oils equal to or greater than 401 degrees F.
JF	jet fuel
KS	Kerosene
LG	liquefied petroleum gases
LU	lubricants
MG	motor gasoline
MS	miscellaneous petroleum products
PC	petroleum coke
RF	residual fuel
WX	Waxes

Energy End-Use Sectors (Characters 3 and 4)	
Code	**Name**
AC	transportation sector estimates
CC	commercial sector estimates
EI	Electric power sector estimates
EU	Electric utility sector estimates
IC	industrial sector estimates
RC	residential sector estimates
TC	total energy sector estimates

Type of Data (Character 5)	
Code	**Name**
B	consumption in Btu. Data are in billion Btu
D	current price per Btu. Data are in dollars per million Btu
P	consumption in various physical units
V	expenditures in current dollars. Data are in millions of dollars

The flowing other tables should be updated as well: BTU to Barrels (conversion factors), GDP87 (Macroeconomic inflators)

This database compiles state and sector level Retail prices to provide Census District retail prices by sector

Markup Estimating Program

The database New Markups.mdb is used to compute the differences in wholesale product prices and retail product prices. For year 2001 prices detailed markups are created for all products by sector by comparing the retail prices computed in SEDS_SEPERS.mdb to the wholesale rack prices published in the Petroleum Marketing Annual. For years 2001 to 2003; Transportation fuels, Heating Oil, and Propane markups are updated by calculating by difference between End-use and "Sales for resale" prices reported in the *Petroleum Marketing Annual, 2003*.

F.5 Estimation of Taxes

In the PMM, taxes are added to the prices of gasoline, transportation distillate fuel (diesel), transportation liquefied petroleum gases (LPG), and jet fuel. Taxes are also estimated for E85 (transportation ethanol) and a placeholder is used for M85 (transportation methanol) because M85 prices are no longer projected by PMM. Weighted averages of the most recently available State and Federal taxes are developed for each Census Division (CD) using periodic State survey data collected by the Defense Energy Support Center (DESC)[17]. The DESC data is then aggregated to the CD level in an analyst's spreadsheet using State annual product volumes obtained from the Petroleum Marketing Annual to calculate a volume-weighted CD average. The spreadsheets utilized for each product are as follows:

Gasoline-	gasoline tax CD volumes.xls
Diesel-	diesel tax CD volumes.xls
Jet-	jet tax CD volumes.xls
E85-	E85 tax CD volumes.xls

The State taxes are fixed in real terms; the Federal taxes decline at the rate of inflation (i.e., Federal taxes are fixed in nominal terms). An additional 2 percent of the retail product CD value is added to the gasoline and diesel taxes to approximate local taxes. Historical values are also calculated for gasoline, transportation distillate, jet fuel and LPG, which are then added to historical end-use prices excluding taxes in order to develop a series with taxes included. The CD taxes, including both historical and projected series by sector, product, and year, are contained in following file, which resides in the default input directory:

MU2PRDS

The Federal taxes are read into the PMM from file:

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17 Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees and Environmental Taxes and Fees," August 9, 2004, Edition: 2004-14.

QDCRDCF

and are updated each forecast year by deflating the current value by the rate of inflation for that forecast year.

The following section traces the development of the taxes and lists the files used to produce both historical and forecast values. The historical data are developed on a monthly basis by State, and then aggregated to volume-weighted annual averages by Census division. The outputs specified are members of the following MSAccess database unless otherwise stated:

SEDS_SEPERS.MDB

Tables: Taxes-MG & Taxes- Diesel & Taxes-E85

Inputs: Tax information from the Defense Energy Support Center
Sources: Gasoline/Diesel "Compilation of United States Fuel Taxes, Inspection Fees and Environmental
                                 Taxes and Fees," July 14, 2005, Edition: 2005-14.

Table: Taxes- LPG & Jet

Inputs: State-level LPG & Jet collected once each year

Sources: Jet fuel   "Compilation of United States Fuel Taxes, Inspection Fees and Environmental
                    Taxes and Fees," July 14, 2005, Edition: 2005-14.
                    LPG   Federal Highway Administration, Table MF-121T

 After compilation each product was then arranged for placement into MU2PRDS.txt. Data for forecast years was then copied from the latest tax information into the future thus preserving the real value of the state taxes as described above.

F.6 Gasoline Specifications

The PMM models the production and distribution of four different types of gasoline: conventional, oxygenated, reformulated, and CARB gasoline. The following specifications are included in PMM to differentiate between conventional and reformulated gasoline blends: octane, oxygen content, Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300).

The sulfur specification for gasoline is reduced to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 ppm between the years 2004 and 2007. PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between now and 2004 is assumed to reflect incentives for "early reduction." The regional assumptions for phasing-down the sulfur in conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

Starting in 1998 the specifications for conventional gasoline reflect the Environmental Protection Agency's (EPA) "1990 baseline." These specifications prevent the quality of conventional gasoline from eroding over time, which is the intent of the EPA's "antidumping" requirements.

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires an oxygen content of 2.7 percent by weight.   Oxygenated gasoline is assumed to have specifications identical to conventional gasoline with the exception of a higher oxygen requirement. Some areas that require oxygenated gasoline will also require reformulated gasoline.   For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Reformulated gasoline has been required in many areas of the United States since January 1995. Beginning in 1998, the EPA has certified reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions either from their companies' 1990 baseline or from the EPA's 1990 baseline. In 2000 the Complex Model was tightened to require further emissions reductions. The PMM has used a set of specifications that meet these   Phase 2" Complex Model requirements, but it does not attempt to determine the optimal specifications that meet the Complex Model. Actually, gasoline currently sold in the United States slightly exceeds the quality implied in the Complex Model 2 specifications (i.e., over-compliance). Thus, in addition to assuming Complex Model 2 compliance for the RFG, *AEO2006* also reflects the "over-compliance" nature of gasoline in general (including conventional gasoline) by adopting the EPA survey of RFG properties in 2004.[18]

The State of California currently uses its own set of performance based gasoline standards instead of the Federal Complex Model standards. The PMM assumes that all West Coast refiners must meet the current California Air Resources Board "CARB 2" requirements until 2003 when a new set of "CARB 3" requirements will take their place.   The CARB 3 standards reflect the removal of the oxygen requirement

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[18]. Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season, U.S. EPA Office of Transportation and Air Quality,   http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm

designed to compliment the State's plans to ban the oxygenate, methyl tertiary butyl ether (MTBE) by the end of 2003.

Other areas of California, do not have an oxygen requirement but use oxygenates because of their octane boosting, and volume extending properties. RFG in the areas with the Federal oxygen requirement is classified in the PMM as "RFG" while CARB gasoline in other areas is classified as "RFH." *AEO2006* reflects legislation which bans or limits the use of MTBE in 25 States: Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New, Hempshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.[19] MTBE is assumed to phase out by the end of 2008 as a result of Energy Policy Act of 2005 (EPACT05) which allows refiners to discontinue use of oxygenates in reformulated gasoline, and on the concern over MTBE's impact to surface water and groundwater resources

Arizona also has a reformulated gasoline program for the Phoenix area which is mandated by State law. Phoenix had previously been part of the Federal RFG program but opted out when State requirements were adopted. Phoenix is required to use CARB in the winter but may use either CARB or Federal RFG in the summer. Arizona is in a different model region than California and, for the sake of simplicity, is assumed to use RFG meeting Federal specifications.

Annual Average RVP Methodology

The annual average RVP limits are derived based on the latest EPA survey of summertime gasoline and estimated wintertime levels.[20] The assumed summer and winter RVP specifications had been annualized by simple averaging using summer and winter weights provided by the EPA.[21] The RVP specifications used in the PMM are shown in Table F8. The lower RVP specifications in PADD V reflect more stringent California limits that are imposed statewide.

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[19]Maine has passed legislation that provides a "goal" of phasing-out MTBE. Since the legislation is not binding, Maine is not included in *AEO2004* assumptions.

[20] *Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season*, U.S. EPA Office of Transportation and Air Quality, http://www.epa.gov/otag/regs/fuels/rfg/properf/rfgperf.htm

[21]The summer weight of 0.396 and winter weight of 0.604 were provided by Dave Korrotney of EPA (313-668-5507).

Table F8. Estimated Annual Reid Vapor Pressure

Gasoline Market/Type	Annual RVP in PMM				
	PADD I	PADD II	PADD III	PADD IV	PADD V
Conventional	9.6	10.2	9.9	10.8	9.2
Reformulated	8.5	9.5	8.6	8.6	7.9

Complex Model Standards for Motor Gasoline

The U.S. EPA has promulgated regulations for reformulated motor gasoline that are designed to lower vehicle emission pollutants as required by the amended Clean Air Act of 1990.[22] The reformulated gasolines are designed to reduce vehicle emissions of toxic and ozone-forming compounds. Reformulated gasoline must be sold in certain regions where there are severe ozone problems as well as in areas with less severe ozone problems which opt into the program. Conventional gasoline may be sold elsewhere but it must not be more polluting than it was in 1990. These areas are discussed elsewhere in the documentation. Although the EPA has established some conventionally treated specifications, namely minimum oxygen content and maximum benzene content, the conceptual aspect of the emission standards is that the reformulated gasoline must be blended in such a way that it meets maximum allowable emissions of volatile organic compounds (VOCs), nitrous oxides (NO_x), and toxics. These motor gasoline standards are calculated by complex formulae based upon key properties of the gasoline blend. The regulations cover Phase I (1 January 1995 through 31 December 1999) and Phase II (1 January 2000 and afterwards). The model uses a set of specifications that meet or exceed emissions requirements for Phase II of the Complex Model. Also, the refiner may meet the requirements for VOCs and NO_x on either a per gallon basis or on an average basis although some per gallon constraints still apply. The average basis has been incorporated into the model.

The NO_x and toxics emission standards for reformulated gasoline apply year-round whereas the VOC standards apply only in the summer. The NO_x standard varies depending upon whether the VOC standards apply, i.e. depending upon whether it is summer or winter. The VOC standard for the north[23] is different from the VOC standard applying to the south, greater volatility is allowed in the north. The Complex Model Averaged Standards are shown below in Table F9.

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[22]Federal Register, Environmental Protection Agency, <u>Regulation of Fuels and Fuel Additives;Standards for Reformulated and Conventional Gasoline; Final Rule</u>, Part II, 40 CFR Part 80, (Washington, DC, 16 February 1994)

[23]For the sake of simplicity, we use the terms south and north to refer to EPA regions 1 and 2 respectively. Region 1 is covered by ASTM Class B while Region 2 is covered by Class C.

Table F9. Complex Model Standards

	Phase I 1995 - 1999	Phase II 2000+
VOC Reduction, %		
South	≥ 36.6	≥ 29.0
North	≥ 17.1	≥ 27.4
NO$_x$ Reduction, %		
Summer	≥ 1.5	≥ 6.8
Winter	≥ 1.5	≥ 1.5
Toxics Reduction, %	≥ 16.5	≥ 21.5
Oxygen, wt%	≥ 2.1	≥ 2.1
Benzene, %	≤ 0.95	≤ 0.95

Source: U. S. Environmental Protection Agency 40 CFR Part 80, *Regulation of Fuels and Fuel Additives: Modifications to Standards and Requirements for Reformulated and Conventional Gasoline*.

These standards were translated into conventionally configured specifications for blending motor gasoline. First, two winter specifications were developed, one for Phase I and one for Phase II. Of course, the VOC standard was excluded from consideration. Then four summer specifications were created, a south set and a north set for Phase I and similarly for Phase II. Specifications for Phase I were used in prior forecasts for years up to 1999. PMM currently uses only the Phase II specifications as 2005 is the initial forecast year. The sulfur specification is adjusted to reflect the regulations requiring the reduction of sulfur in gasoline. RFG is assumed to reach the target of 30 ppm sulfur by 2004.

These sets were developed by use of a spreadsheet, developed by EPA, which calculates the VOCs, NO$_x$, and Toxics of a reformulated gasoline as a function of the 'conventional' properties of the gasoline, i.e. as a function of RVP, sulfur content, oxygen content, aromatics content, olefins content, benzene content, percent evaporation at 200 degrees Fahrenheit (E200), and percent evaporated at 300 degrees Fahrenheit (E300). The approach was to start with 'best informed guess' properties and use trial and error to gradually expand the allowable property limits. The blend properties cited as typical fuels in an EPA presentation[24]

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[24]C.L. Gray, "Reformulated Gasoline Final Rulemaking and Renewable Oxygenate Proposal," Proceedings of The World

served as the starting values for both Phases I and II. The same starting point was used for both winter and summer. Table F11, following a chart developed by the EPA,[25] indicates the directional sensitivities of the properties on the standards. Of course, a more rigorous approach is possible in establishing the specification sets. For instance, one might perform incremental changes over the reformulated gasoline properties followed by computer runs to establish minimum cost specifications. However, this approach was not implemented due to resource constraints.

Table F10. Directional Emission Effects of Gasoline Property Changes

Property	VOC	NO$_x$	Air Toxics
RVP ↓	↓↓↓	'	↓
Sulfur ↓	↓	↓↓↓	↓↓
Aromatics ↓	↓	↓	↓↓
Olefins ↓	–	↓	–
E200 ↑	↓	↑	↓
E300 ↑	↓	–	'
Oxygen ↑	–	'	↓↓
Benzene ↓	'	–	↓↓↓

The PMM is an annual model, i.e. it does not have seasonality. A decision was made to develop, for PADDs I-IV, a single reformulated gasoline specification for Phase I simulation and a single specification for Phase II. This required several actions. The two summer sets for Phase I were linearly blended by combining the projected gasoline sales-weighted south specifications to the appropriately weighted specifications of the north. The resulting two sets of specifications for Phase I, one for summer and one for winter, were then combined after weighting them according to summer sales and winter sales respectively. The Phase II specifications were collapsed to a single set in the same manner. The composites were calculated in a spreadsheet maintained by the Oil and Gas Division. This specification was adapted from the presentation made by Charles L. Gray at the conference cited above. The resulting reformulated gasoline specifications are shown in Table F12. It is, of course, a simple matter to convert the PMM blending stock distillation temperature values as needed.

Conference on Refinery Processing and Reformulated Gasoline, March 22-24, 1994, Information Resources, Inc.
[25]Ibid.

Table F11. PMM Reformulated Gasoline Specifications

	Phase I PADDs I-IV	Phase II PADDs I-IV	Phase II with Reduced Sulfur PADDs I-IV
Max RVP, psia	8.7	8.6	8.6
Max S, ppm	305	108.75	30
Max Aro, %	25.0	25.0	25.0
Max Ole, %	12.0	12.0	12.0
Min E200, %	49.0	49.0	49.0
Min E300, %	87.0	87.0	87.0
Min Oxy, wt%	2.1	2.0	2.0
Max Ben, %	0.95	0.66	0.66

Data represent 2001 specifications to meet Complex Model standards. PMM adopted specifications in each forecast year based on the regulations in effect at the time. Therefore, in 2004 when the Tier 2 regulation kicks in, the maximum sulfur content is reduced to 30 ppm. The sulfur specification on the Complex Model is adjusted to meet Tier 2 gasoline requirements.

F.7 Estimation of Gasoline Market Shares

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, reformulated and CARB gasolines by applying assumptions about the annual market shares for each type. Annual assumptions for each region account for the seasonal and city-by-city nature of the regulations. The market shares are assumed to remain constant at the actual 2004 level.

In 2004, the Census Division 9 market share for RFG is separated into two different categories which represent CARB3 gasoline without an oxygen requirement (RFH) and CARB3 gasoline with the Federal oxygen requirement (RFG). This breakout into another product is needed to represent the planned MTBE ban in California in the absence of a waiver to the Federal RFG oxygen requirement. PMM assumes the Federal oxygen requirement remained intact in the four areas of California bound by the Federal requirement; Los Angeles, Sacramento, San Diego, and the recently added San Joaquin Valley. In effect, these areas must use ethanol to meet the oxygen requirement. The market shares assume that 60 percent of the gasoline in Census Division 9 will continue to meet the Federal RFG requirement, and 15 percent will meet California specifications.

Although the shares are assumed to remain constant after 2004, the PMM structure allows for them to change over time based on alternative assumptions about the market penetration of new fuels. This allows for flexibility to analyze the impact of differing market share assumptions and to adjust the assumptions over time based on updated information about announced participation in the oxygenated and reformulated gasoline programs.

Limitation on MTBE Blended into Gasoline

MTBE is a gasoline blending component used primarily to meet the oxygen requirement of reformulated gasoline specified by the Clean Air Act Amendments of 1990. In the past few years, the use of MTBE has become a source of debate, because it has made its way from leaking pipelines and storage tanks into water supplies. Legislation to ban/limit the use of MTBE in California and 24 other States is modeled as a requirement to produce ethanol blended gasoline in the CHGDMDS subroutine. Ethanol blends are assumed to account for the following minimum market percentages:

> 29.0 percent of RFG in Census Division 1
> 36.5 percent of RFG in Census Division 2
> 99.0 percent of RFG in Census Division 8
> 100.0 percent of RFG (with 2.0 percent oxygen requirement) in Census Division 9
> 100.0 percent of oxygenated gasoline in Census Division 4
> 100.0 percent of oxygenated gasoline in Census Division 8
> 100.0 percent of oxygenated gasoline in Census Division 9

Although MTBE is not explicitly banned in the Energy Policy Act of 2005, concerns for water quality and the removal of oxygenate requirement in RFG by the Energy Policy Act of 2005, the PMM assumes that MTBE would be phased out by 2008. In the qdcrdcf.txt input file, the user can define the allowed volume percent of MTBE (combined with other undesirable ethers) for either or both conventional and reformulated gasolines, and the year the restrictions will go into effect. The constraints are defined mathematically below.

For reformulated gasoline (RFG):

$$\Sigma_{ethers} \, B(r)RFG(ethers) \, \leq \, pct * Q(r)RFG \, + \, pct * Q(r)RFH \, + \, pct * Q(r)SSR$$

and for conventional gasoline (TRG):

$$\Sigma_{ethers} \, B(r)TRG(ethers) \, \leq pct * Q(r)TRG \, + \, pct * Q(r)TRH \, + \, pct * Q(r)SST \, + \, pct * Q(r)SSE$$

where ethers include all or some of the following:

MTBE, ETBE, TAME, TAEE, THME, THEE (all oxygen-containing hydrocarbon compounds)

F.8 Diesel Specifications

PMM models three types of distillate fuel oil: heating oil (N2H), low-sulfur diesel (DSL), and ultra-low-sulfur-diesel (DSU). Both types of the diesel fuel reflect specifications for sulfur, aromatics content, and API gravity. DSL reflects current highway diesel fuel requirements while DSU reflects the tighter "ultra-low-sulfur-diesel"(ULSD) requirement that will begin to be phased-in in 2006. ULSD also covers growing volumes of nonroad, locomotive and marine (NRLM) applications beginning after 2010. DSL in Census Divisions 1 through 8 is assumed to meet Federal specifications including a maximum sulfur content of 500 parts per million (ppm) and a maximum aromatic content of 35 percent by volume.[26] DSL in Census Division 9 is assumed to meet California Air Resources Board (CARB) standards that limit sulfur content to 500 ppm and aromatics to 10 percent by volume.[27]

According to the "ultra-low-sulfur diesel"(ULSD) regulation finalized in December 2000, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. In PMM this new product is assumed to contain 7 ppm sulfur at the refinery gate, reflecting the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

During mid-2004, the U. S. Environmental Protection Agency (EPA) finalized its new nonroad diesel rules which effectively parallel the highway standards but lag by several years in implementation. The specifications and timing of each quality type by refiner class are summarized below.

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[16] Federal regulations require either a maximum 35 percent (volume) aromatics or a cetane index of 40.

[17]http://arbis.arb.ca.gov/diesel/diesregs.pdf

Final U.S. EPA Diesel Fuel Sulfur Limits

Refiner Class	6/1/2006	6/1/2007	6/1/2010	6/1/2012	6/1/2014 +
HIGHWAY DIESEL					
Non-"small" refineries	> 80% 15 ppm		15 ppm		
"Small" refineries (< 155,000 bbl/day; < 1,500 employees)	-		15 ppm		
NONROAD AND LOCOMOTIVE/MARINE (NRLM) DIESEL					
Non-"small" refineries nonroad (NR) diesel	-	500 ppm	15 ppm		
Non-"small" refineries locomotive/marine (LM) diesel	-	500 ppm		15 ppm	
"Small" refineries (< 155,000 bbl/day; < 1,500 employees)	-	-[a]	500 ppm		15 ppm[b]

a. Northeast/Mid-Atlantic requires 500 ppm for all NRLM diesel starting mid-2007.
b. LM diesel downgrade to 500 ppm is allowed indefinitely. Fifteen ppm sulfur is required at refinery gate only.

In late November 2004, after *AEO2005* model runs had been frozen, CARB announced that 15-ppm diesel would be required in harbor-craft in the South Coast Air Quality Management District (SCAQMD, metro Los Angeles) by January 1, 2006.[28] The state ULSD mandate would spread statewide for harbor-craft and intrastate locomotives by January 1, 2007. Given the relatively short lead time (13 months) of the CARB rule, it is uncertain whether this accelerated timetable (versus the Federal nonroad rule) is achievable and whether legal challenges will be mounted in the meantime by affected parties. An abundance of available ULSD arising from the highway program is the rationale for CARB's decision. Since locomotive and marine fuels represent only a very small percentage of California diesel markets, modeling impacts would have been inconsequential in *AEO2005*.

F.9 Estimation of Diesel Market Shares

When fully implemented after 2014, there will be three (3) distillate fuels in the marketplace: (a) 15 ppm highway, (b) Nonroad Locomotive & Marine (NRLM) diesel; (c) high-sulfur heating oil. The PMM has been revised to reflect this new rule and at the same time has been re-calibrated regarding market shares of highway and NRLM diesels, as well as other distillate (mostly heating oil, but excluding jet fuel and kerosene).

Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to non-transportation uses such as agriculture and construction. An offline analysis was performed to re-aggregate diesel fuel by sector and by quality to

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28 "CARB to Mandate ULSD in Locomotives, Harborcraft Between 2006-2007," *World Fuels Today* (November 22, 2004), page 3.

reflect individual uses for the PMM. The following table provides an overview of how the categories were regrouped between the former listings and the new labeled applications.

Distillate Consumption

Fuel Oil & Kerosene Sales Total Distillate Consumption by Sector (adjusted sales)

NEMS (SEDS) Sectors	FO & Kero Sectors			In MMBCD 1998	1999	2000	2001	2002	
U.S. Total				3.461	3.572	3.732	3.847	3.776	
Residential				0.367	0.381	0.399	0.409	0.387	
Commercial				0.199	0.196	0.217	0.229	0.200	
Industrial				0.147	0.142	0.138	0.152	0.146	
	Oil Company			0.037	0.038	0.044	0.054	0.054	
	Farm			0.198	0.189	0.204	0.224	0.207	
		0.35		0.069	0.066	0.071	0.078	0.073	<- "Road" diesel
		0.65		0.129	0.123	0.132	0.146	0.135	<- "Off-highway" diesel
	Off-Highway Diesel			0.142	0.140	0.150	0.164	0.145	
	Total Industrial			0.524	0.508	0.535	0.594	0.552	
Transportation									
	On-Highway Diesel			1.967	2.091	2.161	2.167	2.238	
	Railroad			0.185	0.182	0.197	0.193	0.201	
	Vessel Bunkering			0.139	0.135	0.133	0.137	0.135	
	Military			0.018	0.019	0.015	0.023	0.022	
	Total Transportation			2.308	2.427	2.507	2.519	2.596	
Electric Power				0.063	0.060	0.074	0.095	0.041	
Diesel used for highway diesel engines & Military				1.985	2.110	2.176	2.189	2.260	<- tracked separately from the Transportation Demand Module
Rail (locomotive) & Vessel (marine)				0.323	0.317	0.331	0.330	0.336	<- tracked separately from the Transportation Demand Module
Industrial	(2002 data) 63%	(1998-2002 avg) 63%		0.335	0.320	0.340	0.378	0.350	<- Nonroad Farm + Off-Highway + Industrial High-Sulfur
	22%	22%		0.106	0.108	0.124	0.134	0.124	<- Industrial Low-Sulfur + Farm "Road" Diesel.
	14%	15%		0.083	0.080	0.073	0.082	0.078	<- Industrial HO + No.4
Residential & Electric HO				0.430	0.441	0.474	0.504	0.428	<- Residential and Electric Power use 100% HO (or N2H)
Commercial	(2002 data) 33%	(1998-2002 avg) 32%		0.063	0.060	0.069	0.079	0.066	<- Commercial Low-Sulfur
	16%	15%		0.032	0.031	0.031	0.032	0.031	<- Commercial High-Sulfur
	51%	53%		0.104	0.104	0.120	0.118	0.102	<- Commercial HO + No.4
Highway (Road) Diesel				2.155	2.278	2.369	2.402	2.449	
Non-Road (Off-Highway) Diesel				0.366	0.351	0.371	0.409	0.382	
Locomotive/Marine (LM)				0.323	0.317	0.331	0.330	0.336	
Heating Oil (HO)				0.617	0.626	0.667	0.705	0.609	

The ULSD regulation includes a phase-in period under the "80/20" rule, that requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. The phase-in path for ULSD is determined in the input file QDCRDCF.TXT. As NEMS is an annual average model, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

Heating oil is not subject to ULSD rules. Over two-thirds of all high sulfur distillate use after 2010 will be concentrated in the Northeast.

F.10 Estimation of Regional Conversion Coefficients

Differing regional definitions necessitate the conversions of certain variables from one regional structure to another. Regional conversions are not extensive in the PMM, but are needed for five refinery input prices, refinery fuel consumption, and cogeneration information. The factors are used to convert prices consumption, or cogeneration from census districts to the PADD level since the PMM was originally constructed by PADD.

Conversions for Prices of Refinery Inputs

PMM receives prices for refinery inputs of natural gas from the NGTDM by Census Division and must convert these into PADD level prices. Due to the proximity of refineries in PADDs II, III, and IV to the sources of natural gas supply, prices in these PADD's reflect wellhead natural gas prices in the corresponding Oil and Gas Production Regions. This is achieved by scaling the industrial price for natural gas by an appropriate factor (PNGADJ). Table F12 shows the source of PADD level natural gas prices:

Table F12. Source of PMM Natural Gas Prices

Correlation of Prices	
PADD	**Input Price**
I	Census Division 2 industrial price (PGIIN) * PNGADJ
II	Census Division 3 industrial price (PGIIN) * PNGADJ
III	Census Division 7 industrial price (PGIIN) * PNGADJ
IV	Census Division 8 industrial price (PGIIN) * PNGADJ
V	Census Division 9 industrial price (PGIIN) * PNGADJ

PMM receives prices for refinery inputs of electricity by Census division. PADD level prices are derived by assuming prices in intersecting Census divisions. Table F13 shows the correlation between PADD and Census division electricity input prices:

Table F13. Source of PMM Electricity Prices

Correlation of Prices	
PADD	**Input Price**
I	Census Division 2 industrial prices (PELIN)
II	Census Division 3 industrial prices (PELIN)
III	Census Division 7 industrial prices (PELIN)
IV	Census Division 8 industrial prices (PELIN)
V	Census Division 9 industrial prices (PELIN)

Conversions for Refinery Fuel Consumption

Refinery fuel consumption must be converted from the PADD to the Census division level. Each Census division consumption number will equal the consumption in the overlapping PADD's times a factor. The factors were developed using State-level refinery operating capacity and are shown in Table F14. The factors are interpreted as follows: The 0.8434 at the intersection of Census Division 2 and PADD I indicates that 84.3 percent of the PADD I refinery fuel consumption is estimated (using refinery operating capacity as estimator) to occur in Census Division 2. These values will change by small amounts as refinery capacities change, but the impact on model results will be small.

> Example: Census Division 7 fuel consumption =
> (PADD II consumption * .12) + (PADD III consumption * .93)

Table F14. PADD to Census Division Conversion Factors

	Census Division									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**SUM**
PADD 1		0.84			0.16					1.00
PADD 2			0.60	0.19		0.09	0.12			1.00
PADD 3						0.07	0.93			1.00
PADD 4								1.00		1.00
PADD 5									1.00	1.00

Conversions for Cogeneration

Information including cogeneration levels (RFCGGEN(CD)), cogeneration capacity (RFCGCAP(CD)), refinery fuel consumption (RFCGFUEL(CD)), self-generation (RFCGSELF(CD)), and generation for grid (RFCGGRID(CD)) must also be converted from PADD level to Census divisions. The same factors and methodology developed for refinery fuel consumption (Table F16) are used to convert the cogeneration data.

Conversion coefficients for refinery fuel consumption and cogeneration information are estimated using &6007PRJ.PMM.CAPACITY.COEFS. Manual updates to the data file were made using data from Oil and Gas Journal survey and making some minor adjustments to the program that reads the data.

F.11 Unfinished Oil Imports Methodology

PADDs I and III are the primary recipients of unfinished oil imports into the United States. In recent years, PADD V has started receiving increasing volumes of Resid and Heavy Gas Oils. Accordingly, for *AEO2005*, PADD V has been added and allocation factors have been revised.

The mix of unfinished imported oils flowing into the United States has changed considerably in recent years. An analysis1 is conducted periodically and maintained offline to gauge the relative distribution of principal unfinished oils into the applicable PADDs. Of the four product import categories that EIA publishes, light gas oils are insignificant and not modeled in PMM. Naphtha, Heavy Gas Oil (HGO), and Resid are tracked and modeled. The corresponding product percentage allocation factors by PADD are shown below:

	PADD III	PADD I	PADD V
PADD Allocation Factor	.72	.18	.10
Naphtha	.10	.08	.01
HGO	.60	.77	.33
Resid .	.30	.15	.65

Total unfinished oil imports are estimated as a function of crude oil input to refineries. A regression equation using annual data was developed to represent this relationship and has served over the years despite the erratic timing, magnitude, distribution, and volatility of the various unfinished oil imports into the PADDs. The most significant fundamental shift in unfinished oil imports in recent years has been the dramatic reduction in Resid imports approaching 50 percent. Consequently, the original equation has been modified proportionally to reflect this new circumstance:

U.S. Unfinished Oil Imports = -2856.7 + (0.1224 * Crude Inputs)

Total U.S. unfinished oil imports are estimated from the equation; the PADD values are then allocated to PADDs I, III, and V using the values presented in the above table.

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1 Energy Information Administration, *Petroleum Supply Annual,* June 2004, Tables 3, 5, 9, and 20.

F.12 Product Pipeline Capacities and Tariffs

Three sources were used to obtain the product pipeline data; (1) The NPC study [29] , (2) The North American Crude Oil Distribution (NACOD) model prepared by ICF for the Office of Strategic Petroleum Reserves (OSPR) during 1990-91. (3) Updates to these sources prepared by ICF in July 2003.

NACOD data for the year 2000 were used for the petroleum product pipeline capacities and tariffs (1991$). The NPC study was used for LPG and NGL pipeline capacity data. The NACOD model defines 15 crude oil demand regions (including Canada and Puerto Rico/Virgin Islands) and the NPC study uses PADD regions. The links needed for PMM, as shown in Table F15, are based on PADD's for refining regions and Census Divisions for demands.

Table F15. NACOD Regions and NEMS/PMM Census Regions

NACOD Regions		NEMS/PMM Regions	
Code	Locations	Code	Locations
1	New England	1	NE, New England
2	Includes MD, DE	2	MA, excludes MD, DE
3	WV to FL	5	SA, includes MD, DE
4	KS, OK	7	WSC, includes OK, KS
5	PADD II	3, 4	WNC, ENC, and KY, TN from
6	Texas Gulf Coast	7	WSC
7	LA Gulf Coast	7	WSC
8	West Texas, NM	7	WSC, excludes NM
9	AR, No. LA, No. MS, AL	6, 7	ESC, AR, LA, MS, AL
10	PADD IV, North- ID, MT	8	MNT
11	PADD IV, South-	8	MNT
12	Alaska	9	PAC
13	Hawaii	9	PAC
14	PADD V	9	PAC, excludes NV, AZ

---

[29]National Petroleum Council, *Petroleum Storage and Distribution, Volume 5, Petroleum Liquids Transportation*, (April 1989).

Many of the links shown in Table F16 and Table F17 represent more than one pipeline. In some cases, we have retained more than one link from a source to a destination in order to have a better representation of product movements.

The product pipeline capacities, excluding LPG/NGL service, are shown in Table F16. The matrix formulation used in PMM allows for separate arcs for product movements. For example, to deliver a barrel of gasoline to Dorsey, Maryland (in Census Region 2) from PADD III, (Census Region 7), requires flow on the linl from PADD III to Region 6 (capacity of 2,954 Mbbl/cd) at a cost of $0.38/bbl, flow on the link from Region 6 to Region 5 (capacity of 2,954 Mbbl/cd) at a cost of $0.40/bbl, and flow on the link from Region 5 to Region 2 (capacity of 1,400 Mbbl/cd) at a cost of $0.28/bbl. The total tariff is $1.06/bbl or 2.52 cents/gallon.

Table F16. Petroleum Product Pipeline Capacities and Tariffs

Link from Refinery PADD* to **Census District (CD)**			
From PADD	To CD	Capacity (Mbbl/cd)	Rate (Wt. avg $2002/bbl)
PAD District II	2	136	1.32
PAD District II	6	120	1.32
PAD District II	7	124	0.80
PAD District II	8	136	0.41
PAD District III	3	1,006	1.31
PAD District III	4	40	2.05
PAD District III	8	55	0.82
PAD District III	6	2,954	0.38
PAD District IV	4	106	1.07
PAD District IV	9	73	0.62
CD 5	6	320	0.37
CD 5	2	1,400	0.28
CD 6	5	2,954	0.40

*Some census district source areas are included to represent pipelines that have terminals in more than one CD

Source: July 2003 ICF update..

The LPG/NGL pipelines are shown in Table F17.

Table F17. LPG/NGL Pipelines Capacities and Tariffs

Link from Refinery PADD* to Census District (CD)		Capacity (Mbbl/cd)	Rate (Wt. avg $2002/bbl)
From PADD	To CD		
PAD District I	CD 6	5	2.00
PAD District III	CD 4	50	1.34
PAD District III	CD 3	290	1.17
PAD District III	CD 6	109	0.24
PAD District II	CD 2	56	0.45
PAD District II	CD 7	165	2.48
PAD District II	CD 5	5	0.53
PAD District II	CD 8	5	0.53
PAD District IV	CD 7	160	1.15
PAD District IV	CD 4	60	1.15

*Some census district source areas are included to represent pipelines that have terminals in more than one CD

Source: July 2003 ICF update.

F.13 Cogeneration Methodology

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery cogeneration, and merchant cogeneration. Power generators and cogenerators are modeled in the PMM Linear Program (LP) as separate units which are allowed to compete along with purchased electricity.

Refinery Cogeneration

The refinery cogeneration unit in the PMM LP was modeled using historical data as a guideline. Cogeneration activity for each refinery was aggregated to the PADD level for incorporation into the PMM LP. Cogeneration capacity, fuel consumption, and percent sales to the utility grid were estimated from the EIA-860B, Annual Non-utility Power Producer Report for 2002. The data covers all of SIC 29, not just SIC 2911. Cogeneration investment and operating costs were derived from the 1980 Office of Technology Assessment (OTA) report "Industrial Cogeneration."

Cogeneration capacity (including planned capacity) for each refining region was derived from the EIA-860B historical data base. The LP limits utilization to 90 percent of capacity. Cogeneration capacity is allowed to expand when the value received from the additional product exceeds the investment and operating costs of the new unit. The value of adding capacity includes revenues from sales to the utility grid and the displacement of purchases of electricity. Investment costs are derived from the OTA report. The capacity expansion methodology is described in detail in Chapter 4.

Forecasted Refinery cogeneration fuel consumption was derived from the NEMS Industrial Model for small cogeneration systems. A 1,000 kw capacity unit was assumed with an overall heat rate of 14,217 btu/kwh. Converted to fuel oil equivalent, consumption of 2.26 barrels of fuel oil produces approximately 1,000 kwh of electricity and 6,530 lbs of steam. Since the LP refinery consumes fuel in barrels of fuel oil equivalent, shares of individual fuels were determined from the historical data and computed post process. The shares are allocated as follows:

Oil	6.0%
Natural Gas	68.1%
Other Gaseous Fuels	25.2%
Other	0.7%.

In the past, shares of all petroleum based fuels were aggregated under Petroleum Products. This category has now been divided into Oil and Other Gaseous Fuels.

In general, refinery cogeneration units tend to be small, designed to supply the refinery's steam and electricity needs, with a small amount of leftover capacity sold to the grid. However, if it is profitable to sell cogeneration electricity, the LP will sell all of it. Likewise if it is not profitable, it will sell none of it. To model the situation more realistically, sales to the grid were modeled using percentages derived from the historical data base. The percentage of sales to the grid for each refining region (PADD) was calculated from the 2001 data as follows:

REGION	PERCENT SOLD TO GRID
1 (PADD I)	67
2 (PADD II)	1
3 (PADD III)	1
4 (PADD IV)	1
3 (PADD V)	45

The LP is forced to sell electricity back to the grid in these percentages at a price equal to the average price of electricity.

Fixed operating costs are calculated in the model as a function of cogeneration capacity while variable operating costs are determined as a function of electricity generated. The following rates were determined from the OTA report.

Annual Fixed Cost	$7.32/kw
Variable Cost	$0.00565/kwh

Data from the EIA-860B report obtained from an Access query by Alan Beamon. The resulting data were manipulated in New NUGS.MDB to obtain fuel use, capacity, and capacity factors for existing refinery co-gen units. Output tables become linked input tables for the PMM history file generator "Build ELGCPUR.MDB" described in Appendix H.

Merchant Cogeneration

Merchant cogeneration is also modeled in the PMM. Merchant cogenerators are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. The PMM merchant cogeneration model parameters are based on the Central & South West Energy Inc. (CSWE) facility located adjacent to the Phillips Petroleum Company in Sweeny, Texas. CSWE supplies all of the refinery's steam and electricity requirements and receives up to three quarters of their fuel from refinery waste gases.[30] Electricity not used by Phillips, about two-thirds of total capacity, is sold on the open market.

Fuel consumption parameters for the PMM merchant plant are based on the Sweeny facility. The PMM merchant cogeneration unit consumes 1.90 barrels of fuel oil equivalent to produce 1,000 kwh of electricity and 5,200 lbs. of steam.

Initial capacity in PMM PADDs II, III, and IV is 330 Mw (Sweeny plant). Base capacity in all other regions is zero. Capacity expansion methodology is the same as in the refinery cogeneration model. Investment cost for a new cogeneration facility is $580 per kw of capacity. Annual fixed cost and variable operating cost are the same as for the refinery cogeneration model.

Unlike refinery cogeneration units, merchant facilities tend to be large units designed to sell a large portion of their electricity to the grid. The PMM merchant cogeneration model assumes 67 percent of electricity generated is sold to the grid in all regions, based on the Sweeny facility. The sale price is equal to the average of the generation price and the industrial price of electricity for each PMM region. Electricity prices are obtained from the Electricity Market Model.

F.14 Natural Gas Plant Fuel Consumption

The consumption of natural gas by natural gas processing plants is modeled as a function of dry gas production. Natural gas consumed at gas processing plants is calculated as a percentage of dry gas production using data from the *Natural Gas Annual 1992*. The ratios are calculated by PADD, except for PADD V where Alaska is computed separately from the rest of PADD V.

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[30]CarolAnn Giovando, June 1998. *1998 Powerplant Awards Sweeny Cogeneration Facility*, Power.

PADD I	1.36
PADD II	2.50
PADD III	2.43
PADD IV	2.61
PADD V	2.25
ALASKA	8.93

F.15 Crude Oil Exports/Total and Alaskan

Exports of crude oil have historically been linked to the level of domestic production. A significant amount of crude oil exports used to be from Alaska. Since 2001, however, Alaska has not exported any crude oil due to increasing domestic demand and decreasing crude production in Alaska. This trend is expected to continue. As a result, crude oil exports are represented in the PMM as a percentage of the total lower 48-state crude oil production based on the latest available data

F.16 Technology Improvement Option

A number of mechanisms for representing technological progress for key PMM refinery processing units have been implemented in the PMM. The first option allows the PMM to represent process technology improvements that will impact operating costs on any or all active processing units and/or processing modes. Thus, the user defines the processing unit(s), corresponding processing mode(s), and percentage change in variable operating cost (OVC) (positive or negative), along with a range of years over which these are phased in. The second option allows the user to define a set of processing units and corresponding output streams whose yields would change due to technology improvements. The year in which the technology will come on and the corresponding yields are also included in the input data. The third option allows the user to upgrade the properties of intermediate streams beginning in any user-specified year. The user defines the stream ID, the spec ID(s), and the new spec value(s), along with the activation year for this change. The design for each of these options is modular in that the control data are located in a file separate from the current PMM refinery technology database, and the user defines the information needed to drive the technology change. Each of these options are summarized below.

For the first option, the user has the option to change the OVC data for all processing units (global), for any number of user-defined processing units, for both (with the user-defined unit data over riding the global data), for any set of processing modes, or for nothing at all. The user defines the period over which the OVC change is phased in, as well as the total percentage change (- for a decrease and + for an increase) that is desired over the period. For the user-specified option, the user also includes the 3-digit processing unit ID(s). The last record of data in the user-specified option must begin with a # symbol to signal the end of the list. To turn off either or both options, the phase-in begin and end years must be set to 0. The

control data are located at the bottom of the PMM QDCRDCF data file. The format of this control data is as follows:

```
C Data for Global changes to reflect Technological Progress
C       | Phase-in Period  | Chng over period
C       | BeginYR    EndYR | Percent Chng
@       |     Y1        Y2 | TPCT_CHNG
             0         0      0.0000

C Data for Process Unit changes to reflect Technological Progress
C       | Phase-in Period  | Chng over period  | Name of ProcUnit/ Mode
C       | BeginYR    EndYR | Percent Chng      | Three-letter ID
@       |     Y1        Y2 | TPCT_CHNG         | UNAMID     MNAMID
x             0         0      0.0000            FCC   75H
x             0         0      0.0000            ALK         C4A
#             0         0      0.0             ---         ---
```

To activate the option to *change stream yields* for a processing unit and mode of operation, the user is required to define the processing unit(s), mode(s) and stream(s) being affected, the corresponding new yield level(s), and an activation year (not phased in for this version). The number of processing units, modes, and streams must be included in the data file to act as controls for reading and processing the data. Up to ten modes and ten streams per mode can be changed for each processing unit defined. To deactivate this option, the number of processing units is set to zero. During the processing effort, the original yield and gain levels associated with the processing unit/mode combination are first retrieved from the LP matrix. Next, the yields corresponding to streams specified by the control data are updated based on the input data. Finally, the gain is recalculated and updated in the matrix. The data format representing an activated list of new yield levels is presented below:

```
C Data for Yield improvement to reflect Technological Progress
C   | Num/Name |      |        |    MAX MODES = 10
C   | ProcUnit | Tech | # of   |     1   new |      2   new |     3   new |      4   new
C   | 3-let ID | Year | modes  | mode, coeff | mode, coeff | mode, coeff | mode, coeff|
@   | -------- | ---- | -----  | ----  ----- | ----  ----- | ----  ----- | ----  -----|
       1
      FCC        2005    2       80S             75H
                                  4               8
                                 RC8    .635     UC4    .064
                                 LC8    .099     UC3    .050
                                 UC4    .089     ZR8    .286
                                 COX    .051     ZR7    .286
                                 ---    .000     ZC7    .040
                                 ---    .000     ZC8    .040
                                 ---    .000     LC1    .054
                                 ---    .000     LC2    .055
```

To activate the option to *change spec values* of intermediate streams, the user is required to define the stream(s), spec ID(s), new spec levels, and an activation year (not phased in for this version). The number of streams and spec IDs must also be included in the data file to act as controls for reading and processing the data. Up to ten spec types can be changed for each stream defined. To deactivate this option, the number of streams is set to zero. During the processing effort, the coefficients corresponding to the product

component stream columns (B* and F*) and the product spec requirement rows (Q*) are updated using the stream spec data. Note, however, that a special algorithm must be used when changing the gravity and sulfur specs for streams used for blending into products. The gravity spec (GRX) must be converted using the following equation before being used to update the LP matrix:

$$coef_{gravity} = 141.5 / (131.5 + CHNGSPC_{gravity})$$

The sulfur spec (SLX) data for streams used in blending gasoline and distillate products simply must be divided by 100 (to convert from percent to decimal).

The data format representing an activated list of new spec levels for intermediate streams is presented below:

```
C Data for Spec improvement to reflect Technological Progress
C
C  SELECT FROM THE FOLLOWING LIST OF SPEC IDS:
C      GASO: R0N, M0N, RVX, E2N, E3N, SLX, OLX, ARX, BZX, PON, POX
C      DIST: SLX, GRX, VBX, LMX, FLX, FZX, ARX
C  REQUIRED: WHEN CHANGING SLX, MUST ALSO CHANGE GRX, AND VICE VERSA
C
C  |      |          |       |    MAX NUM OF SPECS = 10
C  | Tech | Stream   | # of  |    1  new |     2  new |     3  new |     4  new|
C  | Year | 3-let ID | specs | spec, value | spec, value | spec, value | spec, value|
@  | ---- | -------- | ----- | ---- ----- | ---- ----- | ---- ----- | ---- -----|
             5
      2005    ZL8       2      BZX  2.50     RVX  10.00
      2005    8LR       3      BZX  2.40     RVX  10.00    ARX  10.00
      2005    ZR8       3      BZX  0.88     GRX  65.00    SLX 200.00
      2005    OR8       3      BZX  2.56     GRX  75.00    SLX  80.00
      2005    BR8       3      BZX  0.18     GRX  50.00    SLX 320.00
```

F.17 GTL Representation in PMM

In the PMM, a gas-to-liquids (GTL) facility can be built on the North Slope in Alaska. A minimum build requirement is 50,000 bbl/d GTL production (gas: ~500MMCFD or 180 BCF a year). The investment and operating costs do not change over time (in constant 1987 dollars). The natural gas supply is represented as a three-step supply curve in the LP. during a forecast year, total quantity on the curve represents the maximum gas used by GTL's at current capacity. Corresponding prices are set using the function CUM_AKNGCRV, which takes into account cumulative North Slope gas production levels. During a build decision year, total quantity on the curve is set to 1.3 times the maximum gas needed for GTL's at current capacity, and prices are set as a function of cumulative North Slope gas production levels that extend 15 years beyond the current forecast year. The CUM_AKNGCRV function contains the following cumulative production/price relationship (provided by the NGTDM team at EIA for AEO2006):

Cumulative production of North Slope NG	Year 2000$/mcf	
$\leq$ 31,000 BCF/yr	Price = $0.80 /mcf	
$\leq$ 36,000 BCF/yr	Price = $1.40 /mcf	
$\leq$ 50,019 BCF/yr	Price = $3.80 /mcf	
$\leq$ 55,276 BCF/yr	Price = $4.00 /mcf	
$\leq$ 60,971 BCF/yr	Price = $4.15 /mcf	
$\leq$ 70,171 BCF/yr	Price = $4.35 /mcf	
$\leq$ 72,362 BCF/yr	Price = $4.55 /mcf	
$\leq$ 76,743 BCF/yr	Price = $4.75 /mcf	
$\leq$ 78,933 BCF/yr	Price = $4.90 /mcf	
$\leq$ 83,314 BCF/yr	Price = $5.10 /mcf	
$\leq$ 85,505 BCF/yr	Price = $5.30 /mcf	
$\leq$ 87,257 BCF/yr	Price = $5.50 /mcf	
$\leq$ 88,133 BCF/yr	Price = $5.70 /mcf	
$\leq$ 92,952 BCF/yr	Price = $6.61 /mcf	
$>$ 92,952 BCF/yr	Price = $7.55 /mcf	

GTL output streams can be transported from the North Slope, through Valdez, to any of the five PMM regions. GTL mixing losses (PMM input) due to transport with the oil along the Trans-Alaska Pipeline System (TAPS) are accounted for and added to the Alaska oil total to be processed in a US refinery. A maximum flow (oil plus gas) is defined along the TAPS pipeline. [A minimum flow could also be defined, but would force the build of a GTL facility if the oil flow is below the minimum.] GTL transport costs from the North Slope to Valdez (along TAPS) are calculated within the PMM as a function of a variable cost, a fixed cost (converted to a unit cost based on t-1 GTL and oil flow), and a subsidy factor (based on value of oil if total flow is below a pipeline minimum—currently deactivated). The fixed and variable costs are determined within the PMM based on input data. GTL transport costs from Valdez to California via vessel are also defined (PMM input).

The following LP variables and coefficients are related to Alaska GTL (and oil) production, transport, and accounting:

TAAMHXZ	Volume of AMH (Alaska medium sulfur - heavy) crude transported from Alaska to Valdez for export to Canada
O@CRDEXP	Other Alaskan crude exports (from South Alaska)
YAAMH5(r)	Volume of AMH crude transported from North Slope to Valdez + to region (r)
YAALL5(r)	Volume of ALL (Alaska low sulfur - light) crude transported from S. AK to region (r)
PADCRQ1	Total Alaskan crude production
TAALLTOT	Total ALL oil produced in Alaska
TAAMHTOT	Total AMH oil produced in Alaska
TAGTLTOT	Total GTLs transported from Alaska North Slope to Valdez along TAPS
TANSOTOT	Total oil transported from Alaska North Slope to Valdez along TAPS
WAGTLJ(r)	Total GTLs transported from Valdez to US refinery regions (r)
GTLLOSS	Percent of GTLs lost due to mixing with Alaska oil during transport along TAPS
H(r)SMD(mod)	Operating level for the SMD GTL processing unit
H(r)SOD(mod)	Operating level for the SOD GTL processing unit
N(r)NGKN1	Alaska NG supply curve, step 1
N(r)NGKN2	Alaska NG supply curve, step 2
N(r)NGKN3	Alaska NG supply curve, step 3
H(r)MPRFSL	Quantity of GTL stream SNL transferred from North Slope to Valdez
H(r)MPRFSP	Quantity of GTL stream SNP transferred from North Slope to Valdez
H(r)MPRFSE	Quantity of GTL stream SKE transferred from North Slope to Valdez
H(r)MPRFSX	Quantity of GTL stream SDX transferred from North Slope to Valdez

The following new and modified equations define the relationship between the variables defined above as related to GTL production in Alaska.

Equation 1
Total GTLs produced in Alaska and transported from the Alaska North Slope to Valdez equals the sum of the individual GTL stream types (produced by each GTL unit's mode of operation) going to each of the 5 PMM regions. The corresponding TAPS transport cost (minus GTL subsidy, if applicable) is applied to the

TAGTLTOT variable. The PRICNS is calculated in the refine.f, and presented in the "Changes to PMM" subsection below. Currently, the GTL subsidy has been deactivated.

CAGTLTOT: TAGTLTOT = $\Sigma_r \Sigma_{gtl}$ H(r)MPRF(gtl)
OBJ: - (PRICNS-GTLSUB) * TAGTLTOT

Equation 2
Total GTLs being transported via a U.S. flag light product vessel from Valdez to PADD (r) equals the total GTLs produced in Alaska, minus the loss due to mixing with Alaskan oil during transport. The corresponding transport cost (cst) is applied to the WAGTLJ(r) variable, and currently set to 3.7, 3.2, 3.2, 3.2, and 0.8 for PADD's 1-5, respectively, in $87/bbl.

C(r)GTL: WAGTLJ(r) = (1. - GTLLOSS) * Σ_{gtl} H(r)MPRF(gtl)
OBJ: - cst * WAGTLJ(r)

Equation 3
The mass balance equation for AMH Alaskan crude was modified to include a gain due to mixing of GTLs during transport. This gain is accounted for in the Alaska North Slope oil stream [YAAMH5(r)].

CAAMH: TAAMHTOT + GLTLOSS * TAGTLTOT =
TAAMHXZ + O@CRDEXP + Σ_r YAAMH5(r)

Equation 4
Since total North Slope Alaska crude does not consist totally of AMH crude, a new variable (TANSOTOT) is created to represent total North Slope Alaska crude, as defined within a new balance row (CANSOTOT). The corresponding TAPS transportation cost for North Slope crude is applied to the TANSOTOT variable. [Note: The OBJ row coefficient on the Y variables now represents other transportation costs from Valdez to the PMM regions.]

CANSOTOT: TANSOTOT = TAAMHXZ +
Σ_r YAAMH5(r) - GLTLOSS * TAGTLTOT
OBJ: - PRICNS * TANSOTOT
OBJ: - coef(r) * YAAMH5(r)

Equations 5,6,7

Two new row constraints are added to account for maximum and minimum flow requirements on TAPS; and, 1 new row constraint to account for maximum NG production in Alaska for GTL use.

TAOILGTX: TANSOTOT + TAGTLTOT ≤ TAPSUL
TAOILGTN: TANSOTOT + TAGTLTOT ≥ TAPSLL
TANGKGTX: $\Sigma_r \, \Sigma_s$ N(r)NGKN(s) <= NGKUL

Equations 8,9
New balance rows were defined for AMH and ALL Alaska crude.

CAAMHTOT: TAAMHTOT = .9844 * PADCRQ1
CAALLTOT: TAALLTOT = .0156 * PADCRQ1

Equations 10-13
Other mass balance additions and changes include mass balance for the GTL stream at the refinery [B(r)(gtl)], mass balance for the GTL stream generated in Alaska [H(r)(gtl)], mass balance for the Alaskan natural gas stream [H(r)NGK], and a capacity limit on the transportation mode (J) [TVPJCP]:

B(r)(gtl):   **(1. - GTLLOSS) * H(r)MPRF(gtl) = $\Sigma_{unt} \, \Sigma_{mod}$ R(r)(unt)(mod) +**
Σ_{prd}F(r)(prd)(gtl) + Σ_{prd} B(r)(prd)(gtl) + T(r)(gtl)(str)

H(r)(gtl):   **Σ_{gtl} H(r)MPRF(gtl) = coef $_{gtl}$ * $\Sigma_{unt} \, \Sigma_{mod}$ H(r)(unt)(mod)**

H(r)NGK: **Σ_s N(r)NGKN(s) = coef $_{ngk}$ * $\Sigma_{unt} \, \Sigma_{mod}$ H(r)(unt)(mod)**

TVPJCP: **. . . + .002 * Σ_r WAGTL(r)**

where,

R(r)(unt)(mod)	Refinery unit (unt) operating level for mode (mod) in region (r)
B(r)(prd)(gtl)	Quantity of GTL (gtl) blended into mogas product (prd) in region (r)
F(r)(prd)(gtl)	Quantity of GTL (gtl) blended into distillate product (prd) in region (r)
T(r)(gtl)(str)	Quantity of GTL (gtl) transferred into blend component (str) in region (r)

Changes to the PMM

Four subroutines (CHGAKTRN, RFGTLCAP, RPTAKGTL CHGTRANS) and a function (CUM_AKNGCRV) in the refine.f code define the new GTL capability in Alaska. In addition, subroutines ADDCAP and CHGBLDLIM handle the PMM ability to specify which processing units are allowed to build. A set of data at the bottom of the rfinvest.txt data file define GTL parameters and control flags. The

data are included below, followed by a list of the GTL variables defined.

In equations 1 and 4 above, the transport price along TAPS (PRICNS) is based on the fixed costs (TAP_FIXCST) and variable costs (TAP_VARCHG).

$$\text{PRICNS} = (\text{TAP\_FIXCST} / (\text{PIPOILNS} + \text{PIPGTLNS})) + \text{TAP\_VARCHG}$$

GTL Data (from rfinvest.txt, version 1.54)

```
========================================================================
PMM input data related to GTL
========================================================================
        Data:           Parameters related to GTL process
        Variables:      GTL_INCBLD   -- incremental GTL output levels for building (Mbbl/d)
                        GTL_FSTYR    -- first possible start year for facility to come on-line
                        GTL_DCLCAPCST -- annual decline rate for capital recovery costs
                        GTL_DCLOPRCST -- annual decline rate for fixed operating costs
        Source: Analyst's judgement
        Notes:
------------------------------------------------------------------------
DOCUMENTATION UPDATES:  DATE--AUTHOR--COMMENT
------------------------------------------------------------------------
NOTES:
------------------------------------------------------------------------
@
        50.0    GTL_INCBLD
        2020    GTL_FSTYR
        0.000   GTL_DCLCAPCST
        0.000   GTL_DCLOPRCST


========================================================================
        Data:           Parameters related to TAPS volumes
        Variables:      TAP_MAXCAP   -- maximum capacity on TAPS (Mbbl/d)
        `               TAP_MINTHRU  -- minimum economic throughput on TAPS (Mbbl/d)
                        TAP_MINSTVOL -- minimum incremental volume above min when subsidy
                        nonzero (Mbbl/d)
                        TAP_PGTLOIL  -- fraction of GTL volume transferred to oil in TAPS (fraction)
        Source:         TAP_MAXCAP   -- analyst's judgment
                        TAP_MINTHRU  -- analyst's judgment
                        TAP_MINSTVOL -- analyst's judgment
                        TAP_PGTLOIL  -- analyst's judgment
------------------------------------------------------------------------
DOCUMENTATION UPDATES:  DATE--AUTHOR--COMMENT
------------------------------------------------------------------------
NOTES:
------------------------------------------------------------------------
@
        3000.00         TAP_MAXCAP
        300.00          TAP_MINTHRU
        100.00          TAP_MINSTVOL
        0.10            TAP_PGTOIL
```

===

Data:	Parameters related to TAPS costs/prices
Variables:	TAP_FIXCST -- fixed transportation cost on TAPS (1000 $/day)
	TAP_VARCHG -- variable transportation cost on TAPS ($/bbl)
	TAP_OILIFT -- assumed oil lifting cost in Alaska ($/bbl)
	TAP_OILADJ -- minimum upward adjustment of lift cost to set total costs (e.g., including profit) (fraction)
Source:	TAP_FIXCST -- judgment based on Alaska Department of Natural Resources graph of tariff rates and volumes
	TAP_VARCHG-- judgment based on Alaska Department of Natural Resources graph of tariff rates and volumes
	TAP_OILIFT -- lifting cost for oil production in Alaska
	TAP_OILADJ -- analyst's judgment

DOCUMENTATION UPDATES: DATE--AUTHOR--COMMENT

NOTES:

TAPS transportation costs (PMM sets oceanic shipping costs elsewhere)

TAPS tariff = (fixed cost / throughput) + variable charge

throughput = oil prod + GTL prod   (mbbl/d)

for build decision:
GTL prod = current CAPgtlns + GTL_INCBLD
Oil prod = PCTAKAMH * 1000* ($XRFQTDCRD_{10}$ + $XRFQTDCRD_{11}$ +$XRFQTDCRD_{12}$) - QEXCRDIN
Oil prod = oil_prod(t) * (oil_prod(t) / oil_prod(t-1))**3.

in general
GTL prod = current CAPGTLNS
Oil prod = oil_prod(t) = PCTAKAMH*RFQTDCRD*1000 - QEXCRDIN

Parameters for calculating GTL subsidy from oil production
if   (oil_prod(t) .le. (TAP_MINTHRU + TAP_MINSTVOL))
then   subsidy = [(oil prod * oil price) - (lift cost * oil prod * (1.+min add)] /GTL prod
----

@	year $	value	
	1995	2055.	TAP_FIXCST
	1995	0.90	TAP_VARCHG
	1999	10.00	TAP_OILIFT
		0.20	TAP_OILADJ

===

GTL Variables

! PUT INTO PMMCOM1 INCLUDE

```
CAPGTLNS(MNUMYR)        ! TOTAL GTL CAPACITY (bbl/d)
TAP_FIXCST              ! FIXED TRANS CST ON TAPS, 1987 dollars
TAP_VARCHG             ! VAR TRANS CST ON TAPS, 1987 dollars/BBL
TAP_OILIFT             ! ASSUMED OIL LIFTING CST IN AK, 1987 dollars/BBL
TAP_OILADJ             ! MIN UPWARD ADJ OF LIFT CST, 1987 dollars/bbl
TAP_MAXCAP             ! MAX CAP ON TAPS, MMBBL/D
TAP_MINTHRU            ! MIN ECONOMIC THROUGHPUT ON TAPS, MMBBL/D
TAP_MINSTVOL           ! MIN INCR VOL ABOVE MINTHRU, MMBBL/D
GTL_INCBLD             ! INCR GTL OUTPUT BLD LEVEL, MBBL/D
PMMCAPI(MNUMPR,PUNITSN)       ! INITIAL REF UNIT CAPACITY, MBBL/D
GTL_FSTYR             ! FIRST POSSIBLE START YR FOR GTL BLD, 4-digit
```

! PUT INTO PMMOUT INCLUDE

```
AKNG_GTLCNS(MNUMYR)  ! CONSUMP OF NG IN AK FOR GTL PROD, Bcf
AKGTLPRD(MNUMYR)       ! GTL PRODUCTION IN AK, Bbl/d
AKGTLEXP(MNUMYR)       ! AK GTL EXPORTS, Bbl/d
```

! PUT INTO OGSMOUT INCLUDE

```
AKNG_SUPCRV(3,2,mnumyr) ! ALASKA NG SUPPLY CURVE, 1987 dollars/mcf, bcf
                        ! 3 - number of points, 2 - price(1),quantity(2)
```

F.18 CTL Representation in PMM

The coal-to-liquids (CTL) process has been incorporated into the PMM. Two options were developed based on methodologies described in a Mitretek Technical Report: *Coproduction: A Green Coal Technology*, by David Gray and Glen Tomlinson, March 2001. Specifically, the large-scale coproduction with no carbon sequestration (Figure 7 in Mitretek report) is adopted as the generic facility for the CTL module, with a second option to include sequestration (Figure 8 in Mitretek report). The CTL facility without sequestration is capable of processing 16,400 TPD bituminous coal (e.g., Illinois Basin) with an energy content of 23 mmBtu/ton, and generating 33,200 BPD of liquid fuels and 465.5 MW <u>net</u> cogen for sale to the grid (based on combined heat and power efficiency of 45%). The CTL facility with sequestration is also designed to process 16,400 TPD bituminous coal (e.g., Illinois Basin) with an energy content of 23 mmBtu/ton. This option can generate 33,570 BPD of liquid fuels and about 309.3 MW <u>net</u> cogen for sale to the grid (also based on combined heat and power efficiency of 45%). The capacity factor (or utilization rate) for the CTL facility is assumed to be 0.9.

A spreadsheet was developed to translate the economic assumptions for this CTL facility into data that could be incorporated in the PMM. The CTL plant life is assumed to be 25 years, with the capital 1/3 from equity at 15 percent and 2/3 from debt with 8 percent of return on investment. Together, this translates into a capital recovery factor of 0.134.

The cogenerated (cogen) electricity is partially consumed in the facility (292 MW and 338 MW with and without sequestration, respectively); while the net cogen is assumed to be sold to the grid at wholesale industrial prices. The revenue from cogen sales is treated as a credit by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTL "liquids." The annualized transmission cost for cogen sent to the grid is accounted for in the operating cost of the CTL facility.

The generic CTL facilities are assumed to be built near existing refineries. The coal types consumed at the CTL facilities are defined within the coal model (CMM) and are based on economic availability. Regionally, the options are:

Padd I   N. Appalachian
Padd II   Western Montana, Wyoming Powder River Basin, Eastern Interior
Padd III   Rocky Mountain, Wyoming Powder and Green River Basin
Padd IV   Dakota Lignite, Powder and Green River Basin
Padd V   Western Montana, Powder and Green River Basin

The CTL yield distribution is assumed to be similar to that from a Gas-to-Liquids (GTL) facility because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to hydrocarbons.

The CTL module allows for a "policy" lever to specify when and how many CTL facilities to be built with government incentives even when it is still economically disadvantaged. Once the CTL becomes economically feasible, its growth rate would be governed by a growth rate based on the Mansfield-Blackman model for market penetration.

Mathematical Representation of CTL in the PMM

The CTL facility is assumed to be located at a site near the representative refinery in each PMM refining region. Thus, coal feed is delivered to this site and processed into synthetic liquids (with cogenerated electricity that is both consumed on site and sent to the grid [transmission costs included]). The liquids are then transported (at a small cost) to the refinery for blending or further processing.

A single (representative) coal type is modeled within each region. The quantity, delivered price, and average heat content (LCVTONQ, LCVTONP, and LCVBTU) of each coal available for processing, as well as a price elasticity (LCVELAS), are provided by the CMM. The quantity of coal consumed to produce 33,200 bbl/cd liquids at each CTL facility is a function of the average heat content of the coal provided by the CMM and the base energy content and consumption level of the coal defined for the representative CTL processing unit (BASCLRAT * CTL_BASHHV / LCVBTU). The PMM uses the price, quantity, and elasticity to build a 5-step coal supply curve. The final quantity of coal demanded (Q_CTLCOAL) is sent back to the CMM for response.

The CTL processing mode is based on a representative GTL processing mode from the PMM technology database provided by Ensys. The input rate (tons coal per bbl liquid produced) has been adjusted to reflect the corresponding coal to liquids ratio presented in the Mitretek paper. Special links have been established to ensure the "liquids" will be processed or blended properly downstream. Cogeneration is accounted for at the CTL facility as a function of the liquids produced. A credit (a function of end-use electricity prices, PELIN) is provided to account for sales to the grid.

Capital costs for the CTL facility are based on the cost information provided by Mitretek, including both fixed charges and other operating costs. Also, in accordance with direction from Mitretek, these costs are increased depending on the coal type consumed in the region. Two decline-rate variables (CTL_DCLCAPCST, CTL_DCLOPRCST) have been included to allow for costs to improve over time. Also, a NEMS runtime variable (CTLSEQSW) was added to control the CO_2 sequestration option for the CTL facilities.

The "policy" lever included with the CTL to reflect government incentives consists of a minimum build forecast series. This is tracked as a separate CTL processing unit (CTZ vs CTX) in order to distinguish

between incentives builds (CTZ) and economic builds (CTX). Also, the Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTLs (on a national level) once they become economically feasible.[31] The indexes associated with this modeling algorithm are user inputs that define the characteristic of the CTL process. They include an innovation index of the industry (IINDX), the relative profitability of the investment within the industry (PINDX), the relative size of the investment (per plant) as a percentage of total company value (SINVST), and a maximum penetration level (number of units, CTLBLDX). These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTL) technology in NEMS," dated March 23, 2002.

Carbon dioxide emissions are handled by the NEMS integrating model by applying a CO_2 emissions coefficient to the coal consumed by the CTL unit.

---

[31] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765.

A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

Updates to the LP matrix

The following LP variables are directly related to CTL production, transport, and accounting:

rows:

C(r)CTLTOT	Total CTL liquids produced for refinery (1000 bbl/cd)
E@CTXMBX	Totals CTL capacity built in a forecast year (national) (1000 bbl/cd)
L(r)CTXCAP	CTL capacity balance net of incentive builds (1000 bbl/cd)
L(r)CTZCAP	CTL capacity balance from incentive builds (1000 bbl/cd)
H(r)(liq), B(r)(liq)	CTL liquids balance (1000 bbl/cd)
H(r)(coal)	Coal (into CTL unit) balance (1000 tons/cd)

columns:

B(r)(gaso)(liq)	CTL liquids blended into gasolines (M bbl/cd)
F(r)(dist)(liq)	CTL liquids blended into distillates (M bbl/cd)
	[DSL, DSU, JTA, N2H, N6I]
K(r)CTXCAP	Existing CTL processing unit capacity, =0 (M bbl/cd)
E@CTXINV	Total CTL capacity built in 1 forecast year (national), with UL set by M-B penetration algorithm (M bbl/cd)
E(r)CTXINV	CTL processing unit additions (M bbl/cd)
L(r)CTXBLD	Cumulative CTL unit additions (M bbl/cd)
H(r)CTX(mod)	Operating level for CTL (M bbl/cd)
K(r)CTZCAP	Existing planned CTL processing unit capacity, =0 (M bbl/cd)
E(r)CTZINV	planned CTL processing unit additions (M bbl/cd)
L(r)CTZBLD	Cumulative planned CTL unit additions (M bbl/cd)
H(r)CTZ(mod)	Operating level for planned CTL (M bbl/cd)
R(r)(unt)(mod)	New mode to process liquids from CTL units (M bbl/cd)
H(r)MPRF(liq)	Vol of CTL liquids transferred to refinery (M bbl/cd)
N(r)(coal)N(step)	Coal supply curve for CTL processing (1000 tons coal/cd, 87$/ton)

The following equations define the relationship between the variables defined above as related to CTL production.

Equation 1

Coal supply mass balance: The coal supply (represented as a 5-step coal supply curve) must equal the coal consumed at the CTL units (including planned units) to produce liquids (by region/coal type).

H(r)(coal): $\sum_s N(r)(coal)N(s) = \sum_{mod} c_l * H(r)CTX(mod) + \sum_{mod} c_l * H(r)CTZ(mod)$
[1000tons/cd]

Equations 2 & 3

Liquids production mass balance: Liquids produced at the CTL unit must equal the liquids transferred to the refinery (by region and liquid type). CTL liquids transferred to the refinery are either consumed by other processing units, blended into mogas, or blended into distillates (by region and liquid type).

H(r)(liq): Σ_{mod} c$_2$ * H(r)CTX(mod) + Σ_{mod} c$_2$ * H(r)CTZ(mod) = H(r)MPRF(liq)
[1000bbl/cd]

B(r)(liq): H(r)MPRF(liq) = Σ_{dist} F(r)(dist)(liq)   **< distillates >**
[1000bbl/cd]
　　　　 -- or --
　　　　　 H(r)MPRF(liq) = Σ_{mgas} B(r)(mgas)(liq) + Σ_{unt} Σ_{mod} R(r)(unt)(mod)   **<mogas>**

Equation 4

CTL operating/capacity balance and penetration limit: Total operating level of CTL must equal the operating level of existing CTL capacity, newly added capacity, and cumulative added capacity. Total operating level cannot exceed upper bounds on existing, newly added, and cumulative added capacity (by region). Newly added capacity is limited to a national level defined by the M-B penetration algorithm, set as the upper limit on the "capacity added" variable (E@CTXINV).

L(r)CTXCAP: 　　　 Σ_{mod} H(r)CTX(mod) = K(r)CTXCAP + cf*E(r)CTXINV +
　　　　　　　　 cf*L(r)CTXBLD

[1000bbl/cd]

L(r)CTZCAP: 　　　 Σ_{mod} H(r)CTZ(mod) = K(r)CTZCAP + cf*E(r)CTZINV +
　　　　　　　　 cf*L(r)CTZBLD

[1000bbl/cd]

E@CTXMBX: 　　　 **E@CTXINV** = Σ_r E(r)CTXINV
[1000bbl/cd]

Equation 5

Total CTL liquids produced: This unconstrained row totals CTL liquids produced (by region), for reporting.
C(r)CTLTOT: 　　　 Σ_{liq} H(r)MPRF(liq)
(1000 bbl/cd)

Equation 6

Objective function: A credit is put in the objective function, attached to the CTL operating variable, to account for cogen produced at the CTL and sent to the grid. A cost is added to the objective function, attached to the transfer variables H(r)CTX(mod) and H(r)CTZ(mod), to account for the transfer tariffs from CTL facility to refinery. Variable operating costs and capital investment costs are included in the objective function for the E, L, and H variables. The cost of coal on each supply step is included in the objective function

OBJ: $\quad$ Σ_{mod} Σ_r **CgnCredit * H(r)CTX(mod) +** Σ_{mod} Σ_r **CgnCredit * H(r)CTZ(mod)**

[1000$/cd] $\quad$ **+** Σ_{liq} **tariff_liq * H(r)MPRF(liq)**

$\qquad\qquad$ **+ inv_cst*E(r)CTXINV + inv_cst*L(r)CTXBLD**

[$\qquad\qquad$ **+ inv_cst*E(r)CTZINV + inv_cst*L(r)CTZBLD**

$$+ \ \Sigma_s \ \Sigma_r \ \Sigma_{coal} \ \text{coal\_cst}_{s,r,coal} * N(r)(coal)N(s)$$

where,

CgnCredit $\quad$ = PELIN( ) * CFELBK * CTL_CGGFAC *24.
(87$/bbl liq)

coal_cst $\quad$ = P_o * [Q / Q_o]^{elas}
(87$/ton coal)

tariff_liq $\quad$ = from CMM
(87$/bbl liq)

inv_cst $\quad$ = calculated in refine.f from investment data (includes annualized transmission cost for
(87$/bbl liq) $\quad$ cogen to grid from CTL facility)

Updates to the PMM refine.f code

Three new subroutines (CHGCTLCOEF, PMMCTL_BLDLIM, and RPTRFCTL) were added, along with
other minor changes in the refine.f code to reflect the new CTL capability. Also, a new set of data was
added to the rfinvest.txt data file (before the GTL data) to define CTL parameters and control flags. The
new CTL data are included in the Attachment at the end of this section.

The PMMCTL_BLDLIM subroutine sets both minimum and maximum build allowances for the CTL. The
minimum build represents builds based on government incentives before it is economic to build. This is
defined by a forecast series in the rfinvest.txt input file (CTL_PLNBLD) and is associated with the
planned CTL unit (CTZ). Once CTL builds are economical, the maximum build allowance is determined
using the Mansfield-Blackman model for market penetration. It tracks the number of units built nationally
to determine the maximum penetration allowed for the next build cycle. This is applied to the mainstream
CTL unit (CTX).

The CHGCTLCOEF subroutine updates the relevant CTL coefficients with data provided by the CMM
and the EMM. These include the coal supply curve price and quantity levels (and elasticity used to define
the coal supply curve), the credit and transmission costs for cogenerated electricity sent to the grid, the
tariff for transferring CTL liquids to the refinery, and the adjustment to the coal consumption ratio based
on coal heat content. The coal supply curve equation takes the following form:

$$\text{New delivered price of coal} = \left(\frac{(\text{LCVTONQ} + \text{delta})}{\text{LCVTONQ}} \right)^{\text{LCVELAS}} * \left(\text{LCVTONP} \right)$$

where,
$\qquad$ delta = change in supply curve quantity

LCVTONQ =   Coal supply curve production level (mil tons/yr)
LCVTONP =   Coal supply curve delivered pr (87$/ton)
LCVELAS =   elasticity fo coal supply curve

The RPTRFCTL report subroutine retrieves CTL solution results from the LP matrix and stores them into special variables -- some are passed to the CMM or to FTAB for reporting, while others are used in the PMM output tables (pmmrpts.txt). These include:

CLMINEP(mnumpr,mnumyr)   ! minemouth CTL coal pr
CTL_CGCGD(mnumpr,mnumyr)   ! CG cap from CTL--to grid
CTL_CGGGD(mnumpr,mnumyr)   ! CG gen from CTL--to grid
P_CTLCOAL(mnumpr,mnumyr)   ! PR coal used for CTL (87$/ton)
Q_CTLCOAL(mnumpr,mnymyr)   ! QTY coal used for CTL (M ton/cd)
Q_CTLPRD(mnumpr,mnumyr)   ! QTY liquids produced from CTL
QCLRFPD(mnumpr,mnumyr)   ! Quantity of coal for CTL (trillion Btu)
RFCTLPRD(mnumpr,mnumyr)   ! Quantity of liquids from coal (thousand barrels per day)

Within the existing RFUPD8_INV subroutine, an adjustment factor (CSTFAC) was added to the CTL costs to account for the added investment costs associated with using lignite and sub-bituminous coals. This adjustment factor is a user input, defined in the rfinvest.txt input file (CTL_CSTFAC). Also added to the cost total is the annualized transmission cost for sending cogen to the grid (two charge factors provided by the EMM: TRCTLOVR, TRCTLFCF).

In the sprflrt.txt input file, a new set of look-ahead data has been added. These include the prices, quantities, elasticities, coal transit costs (XLCVTONP, XLCVTONQ, XLCVELAS, XLTRNTON) and the BTU content of the coal (XLCVBTU), provided by the CMM for all regions and years. Thus, the impcurv.txt output file also includes these variables.

(Note: What used to be the COALCOEF was changed to the OGASCOEF for clarity. A CF correction was made to the PUBASE calculation. The cogen from CTL was put into the "other" category in the variables CGREQ, CGRECAP, CGREGEN, but classified as coal for ftab reporting.)

CTL Data in the rfinvest.txt (version 1.54) input file

```
========================================================================

PMM input data related to CTLs-- Coal-to-Liquids

========================================================================

      Data:  Parameters related to CTL process
 Variables:  CTL_INCBLD   -- incremental CTL output levels for building (Mbbl/d)
             CTL_FSTYR    -- first possible start year for facility to come on-line
             CTL_DCLCAPCST -- annual decline rate for capital recovery costs
             CTL_DCLOPRCST -- annual decline rate for fixed operating costs
             CTL_BASHHV   -- coal HHV (mmBTU/ton)-- basis used for CTL yields data
             CTL_BASSIZ   -- CTL base size (1000 bbl/cd liq output)
             CTL_BASCOL   -- CTL base coal consump (1000 tons/cd) -- bituminous
             CTL_BASCGS   -- CTL base cogen to self (MW)
             CTL_BASCGG   -- CTL base cogen to grid (MW)
             CTL_BASCGF   -- CTL base cogen capacity factor
             CTL_NAM      -- coal type ID for CTL
             CTL_CSELAS   -- elasticity for coal supply curve, by coal type
             CTL_CO2FAC   -- lbs CO2 emitted/bbl liq produced
             CTL_CGNFAC   -- Fac to est elec cogen to Grid fr CTL (kWh/bbl liq)
             CTL_CSTFAC   -- Fac to adj CTL cap/op cost based on coal type (10% for
                    LIG, SUBBIT vs BIT)
             CTL_CLHHV    -- coal HHV (mmBTU/ton)
             P_CTLTRN     -- Cost to transport CTL liq from facility to refinery
                    ($/bbl)
             CTL_LIQNAM   -- Name of liq streams from CTL process
             CTL_PLNBLD   -- CTL planned build series (cum # of units at base size)

        ****Investment info from "Coproduction: A Green Coal Technology" Mitretek
             CTL_YRCST    -- year $ for investment costs
             CTL_NFOPCST  -- Non-fuel operating costs (MM$/yr)
             CTL_CAPREQ   -- Total capital requirement (MM$)
             CTL_FXREC    -- Fixed cost recovery factor (rate)

        ****Mansfield-Blackman model variables****
             CTLMB_SW     -- switch to apply M-B model to max bld (1=yes)
             CTLBLDX      -- max CTL penetration
             IINDX        -- innovation index
             PINDX        -- relative profitability ratio
             SINVST       -- investment ratio

    Source:  Analyst's judgement
     Notes:

------------------------------------------------------------------------
DOCUMENTATION UPDATES:  DATE--AUTHOR--COMMENT
------------------------------------------------------------------------
NOTES:
  04-02-03 em4     CTL BASCGG chg'd fr 696.0 to 465.5 to represent a 46% CHP
                   efficiency (vs 60% eff). This was calc'd as follows:
                   [ (292 *696) * (46% /60%)] - 292 = 465.5
  02-16-05 em4     Flag CTL_SEQFLG determines if CTL will be modeled
                   w/ (=1) or w/o (=0) sequestration
                   (CTL_SEQFLG is set by the runtime parameter CTLSEQSW)
                   Data corresponding to CTL w/ sequestration is after data w/o seq.
------------------------------------------------------------------------
@
      33.2     CTL_INCBLD      (Mbbl/cd of liq produced)
```

```
        2011          CTL_FSTYR
        0.000         CTL_DCLCAPCST    (fraction)
        0.000         CTL_DCLOPRCST    (fraction)
       23.00          CTL_BASHHV       (mmBtu/ton coal)
       33.20          CTL_BASSIZ       (1000 bbl/cd liq produced)
       16.40          CTL_BASCOL       (1000 ton/cd coal)
      292.0           CTL_BASCGS       (MW per year)
      465.0           CTL_BASCGG       (MW per year)  >> see note above 4-2-03
        0.900         CTL_BASCGF       (fraction)

@    CTL_CO2FAC CTL_CSTFAC
3
CL1E   0.000      1.000
CL2C   0.000      0.850
CL3G   0.000      1.300
CL4M   0.000      0.800
CL5W   0.000      1.000

     Source: "Coproduction: A Green Coal Technology" Mitretek
@
        1998       ! CTL_YRCST      -- year $ for investment costs
      117.710      ! CTL_NFOPCST    -- Non-fuel operating costs (MM$/yr)
        2161.      ! CTL_CAPREQ     -- Total capital requirement (MM$)
        0.134      ! CTL_FXREC      -- Fixed cost recovery factor (rate) <- per Tom Lee,
                     8/16/05

  =====                             =====
  ===== End of data for CTL w/o sequestration   =====
  =====                             =====


  =====                                              =====
  ===== the following data are for CTL w/  sequestration (CTL_SEQFLG=1) =====
  =====                                   (runtime parameter CTLSEQSW=1) =====
  =====                                              =====
@
       33.57          CTL_INCBLD       (Mbbl/cd of liq produced)
        2011          CTL_FSTYR
        0.000         CTL_DCLCAPCST    (fraction)
        0.000         CTL_DCLOPRCST    (fraction)
       23.00          CTL_BASHHV       (mmBtu/ton coal)
       33.57          CTL_BASSIZ       (1000 bbl/cd liq produced)
       16.40          CTL_BASCOL       (1000 ton/cd coal)
      338.0           CTL_BASCGS       (MW per year)
      309.3           CTL_BASCGG       (MW per year)  >> see note above 2-16-05
        0.900         CTL_BASCGF       (fraction)

@    CTL_CO2FAC CTL_CSTFAC
5
CL1E   0.000      1.000
CL2C   0.000      0.850
CL3G   0.000      1.300
CL4M   0.000      0.800
CL5W   0.000      1.000

     Source: "Coproduction: A Green Coal Technology" Mitretek
@
        1998       ! CTL_YRCST      -- year $ for investment costs
      142.500      ! CTL_NFOPCST    -- Non-fuel operating costs (MM$/yr)
        2244.      ! CTL_CAPREQ     -- Total capital requirement (MM$)
        0.134      ! CTL_FXREC      -- Fixed cost recovery factor (rate) <- per Tom Lee,
                     8/16/05

  =====                             =====
  ===== End of data for CTL w/  sequestration   =====
```

```
   =====                                          =====

    Source: Memo from Andy S. Kydes, March 23, 2002
              "Development of a model for optimistic growth rates for the
               coal-to-liquids (CTL) technology in NEMS"
@    Parameters for Mansfield-Blackman model for CTL bld series
          1         ! CTLMB_SW: switch to apply M-B model to max bld (1=yes)
        300.        ! max number of CTL unit blds allowed (not capacity)
       -0.30        ! I: innovation index
        1.25        ! Pr: relative profitability ratio
        2.00        ! SI: size of investment ratio

    Cumulative planned CTL builds (number of CTL units, not capacity)
@  REG     YEAR   NUM
     2     0000     1   end series with 0000 for year

    --TEMP CLT -- until coal model is completed
@      LTRNTON   LCVELAS   LIQUCARB   LIQUSUL   LIQUBTU
CL1E   0.000     1.000     0.000      0.000     25.00        Appalachian Bit
CL2C   0.000     1.000     0.000      0.000     23.00        Ill Basin   Bit
CL3G   0.000     1.000     0.000      0.000     23.00        Texas ??
CL4M   0.000     1.000     0.000      0.000     17.38        Powder Riv  SubBit
CL5W   0.000     1.000     0.000      0.000     17.38        Powder Riv  SubBit

    Liquid stream ID's (CTL_LIQNAM) and
@    transfer costs (P_CTLTRN)
4      CL1E      CL2C      CL3G      CL4M      CL5W
CNL    1.500     1.500     1.500     1.500     1.500
CNP    1.500     1.500     1.500     1.500     1.500
CKE    1.500     1.500     1.500     1.500     1.500
CDX    1.500     1.500     1.500     1.500     1.500


========================================================================
```

F.19 Petroleum Coke Gasification Representation in PMM

The coke gasification processing unit represented in the PMM was designed by NETL, as described in their document to EIA, "Refinery Technology Profiles: Gasification and Supporting Technologies," June 2003. [32] NETL carried out extensive research on the gasification process and the PMM model design to generate data tables that realistically represented the coke gasification process (with a combined heat/power (CHP) option) that fit into the PMM process data structure. The data tables were reviewed and modified slightly by EIA to better integrate it into the PMM LP structure. The original design allowed either petroleum coke feed or asphalt feed; however, only the coke feed design was adapted into the PMM due to competition issues between the coke and asphalt feeds.

The coke gasification unit is designed to gasify high sulfur petroleum coke to produce either synthetic gas (SGS) or hydrogen (and synthetic gas). In order to properly represent the difference in investment costs between hydrogen and syngas production, separate gasification units are modeled in the LP (identified as GSH and GSF, respectively). The product hydrogen is put into a pool stream to be used by other processing units at the refinery. The product synthetic gas (with natural gas backup) is routed through a combined heat and power (CHP) unit to produce both steam and electricity, or electricity only. Based on NETL research, the CHP unit assumes a syngas to natural gas consumption ratio of 90:10 during a typical year. Also, a grid/self split was defined in the PMM input files to track the destination of cogen electricity produced by the CHP. The byproduct H_2S is also produced for all options and sent to an H_2S pool.

The design size of the coke gasification unit was set to 2000 short tons of coke feed per calendar day (s-tons/cd), at an ISBL cost of $160MM (syngas) and $194MM (hydrogen), in 1993$. The ISBL cost for the CHP was set to $134.9MM (1993$), for a standard 8.11 bbl FOE/cd (2044 MM BTU/cd) syngas/natural gas throughput. NETL also provided regional starting capacity for the coke gasification units (see below). These levels were used to establish initial capacity for the CHP units, where applicable. The capacity factor (or utilization rate) was assumed to be 0.85 for the gasification units, and 0.96 for the CHP unit.

Starting CTL Unit Capacities by PADD

	I	II	III[*]	IV	V	
GSF	2.10	0.17	5.05	0.00	0.00	(M s-tons/cd)
GSH	0.00	1.10	0.00	0.00	0.00	(M s-tons/cd)
CHP	8.03	1.06	10.0	0.00	0.00	(M bblFOE/cd)

* minimally defined capacity to prevent infeasibility

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[32] Hohn, Marano, Ph.D.,"Refinery Technology Profiles: Gasification and Supporting Technologies," National Energy

Mathematical Representation of Coke Gasification Process in the PMM

The coke gasification process added to the PMM consumes high sulfur petroleum coke (CKH-- typically from the delayed or fluid coker at the refinery) and produces hydrogen (HYH) and/or syngas (SGS) [and some hydrogen sulfide (H2S)]. The HYH and H2S are consumed or processed at the refinery, while the SGS (with natural gas as the backup fuel 10% of the year) is sent to the combined heat/power (CHP) unit to generate steam (STM) and/or electricity (KWH). Some of the electricity is sold to the grid, with the remaining consumed at the refinery. The LP variables and constraints created or modified to represent this entire process are presented below:

Definitions (**bold** means new):

GSF	= coke gasifier unit producing synthetic gas
GSH	= coke gasifier unit producing hydrogen
CHP	= combined heat and power unit
CK1, CK2	= operating modes for coke gasifier units
CKH	= high sulfur petroleum coke
SGS	= synthetic gas
NGS	= natural gas
HYH	= hydrogen (high quality)
H2S	= hydrogen sulfide
FUL	= combined fuel pool
KWH	= electricity
STM	= steam
OVC	= variable operating costs
FXOC	= fixed operating costs
INVST	= capital investment costs
OBJ	= objective function row
R-var	= LP column variable for unit operating level
X-var	= LP column variable representing coke sent to meet demand
K-var	= LP column variable for unit operating level of initial capacity
E-var,L-var	= LP column variable for unit operating level of new capacity
m, mod	= operating mode
c	= coefficient (all unique values)
r	= PMM refinery regions (Padd)
d	= Census demand regions

Technology Center, for DOE/EIA, June 2003.

Stream/Utility Balance Rows:

These constraints require the supply levels for a stream to equal the demand levels for that stream, within each refinery region (r). This applies to coke (CKH), syngas (SGS), natural gas (NGS), hydrogen (HYH), hydrogen sulfide (H2S), fuel (FUL), electricity (KWH), and steam (STM). The only entirely new stream balance row is for syngas.

B(r)CKH: Σ_m c*R(r)KRD(mod)   **- R(r)GSFCK1**

[M s-ton/cd] $+\Sigma_m$ c*R(r)KRF(mod)   **- R(r)GSHCK2**

                                           - c* X(r)CKHCOK = 0

B(r)SGS: *c* R(r)GSFCK1*   *- Σ_m c*R(r)CHP(mod)*

[M bbl FOE/cd]   *+c* R(r)GSHCK2*   *= 0*

B(r)NGS: . . . . .   *- Σ_m c*R(r)CHP(mod)*   = 0

[M bbl FOE/cd]

B(r)HYH: . . . . .   *+ c* R(r)GSHCK2*   = 0

[M bbl FOE/cd]

B(r)H2S: . . . . .   *+ c* R(r)GSFCK1*   *+ c* R(r)GSHCK2*   = 0

[M bbl FOE/cd]

B(r)FUL: . . . . .   *- c* R(r)GSHCK2*   = 0

[M bbl/cd]

U(r)KWH: . . . . .   *- c* R(r)GSFCK1*   *- c* R(r)GSHCK2*

[M kWh/cd]   *+ Σ_m c*R(r)CHP(mod)*   = 0

U(r)STM: . . . . .   *- c* R(r)GSFCK1*   *- c* R(r)GSHCK2*

[M lb/cd]   *+ c*R(r)CHPCO1*   = 0

capacity expansion/investment rows:

New capacity constraints are defined for the GSF, GSH, and CHP units. These constraints require the total operating level of each unit to be less than or equal to the total available capacity (existing + new). The accounting row (A(r)CHPCGN) keeps track of total electricity generated by the CHP unit in each refinery region. The P(r)OVC row accumulates the OVC for each processing unit (defined in 2000 year dollars) and uses the variable T(r)OVCOBJ to convert to 87$ and put into the objective function. The FXOC and

INVST rows are accounting rows for PMM reports. The objective function row (OBJ) includes the investment costs for the new processing units.

L(r)GSFCAP: *c* R(r)GSFCK1*   *- K(r)GSFCAP*

[M s-tons/cd]   *- c* E(r)GSFINV*   *-c* L(r)GSFBLD*   *<= 0*

L(r)GSHCAP: *c* R(r)GSHCK2*   *- K(r)GSHCAP*

[M s-tons/cd]   *- c* E(r)GSHINV*   *-c* L(r)GSHBLD*   *<= 0*

L(r)CHPCAP: Σ_m *c* R(r)CHP(mod)*   *- K(r)CHPCAP*

[M bbl FOE/cd]   *- c* E(r)CHPINV*   *-c* L(r)CHPBLD*   *<= 0*

A(r)CHPCGN: Σ_m *c* R(r)CHP(mod)*   (accounting row)

[M kWh/cd]

P(r)OVC: . . . . .   *- c* R(r)GSFCK1*   *- c* R(r)GSHCK2*

[M $2000/cd]   *- Σ_m c*R(r)CHP(mod)*   + c* T(r)OVCOBJ   = 0

A(r)FXOC: . . . . .   *+ c* E(r)CHPINV*   *+ c* L(r)CHPBLD*   (accounting row)

(A@FXOC, $\Sigma_{r..}$)   *+ c* E(r)GSFINV*   *+ c* L(r)GSFBLD*

[M $87/cd]   *+ c* E(r)GSHINV*   *+ c* L(r)GSHBLD*

A(r)INVST: . . . . .   *+ c* E(r)CHPINV*   *+ c* E(r)GSFINV*   (accounting row)

(A@INVST, $\Sigma_{r..}$)   *+ c* E(r)GSHINV*

[M $87/cd]

OBJ: . . . . . Σ_r *[- c* E(r)CHPINV*   *- c* L(r)CHPBLD*

[M $87/cd]   *- c* E(r)GSFINV*   *- c* L(r)GSFBLD*

               - c* E(r)GSHINV   *- c* L(r)GSHBLD*

               + Σ_m c*R(r)CHP(mod)]

Bounds put on the following variables:

The initial capacity for each of the new processing units are defined as upper limits on the K-variables. Added capacity for the new units are set as bounds on the E-variables (capacity added this year) and on the L-variables (accumulated capacity added in previous years).

[M s-ton/cd]   *K(r)GSFCAP*   *E(r)GSFINV*   *L(r)GSFBLD*

| [M s-ton/cd] | **K(r)GSHCAP** | **E(r)GSHINV** | **L(r)GSHBLD** |
| [M bbl FOE/cd] | **K(r)CHPCAP** | **E(r)CHPINV** | **L(r)CHPBLD** |

Updates to the PMM Fortran code

In addition to updating the LP matrix structure, various PMM code changes were needed for proper accounting and reporting, as well as for model consistency and stability. First, for FTAB reporting, the resulting cogen electricity production levels were categorized as grid vs self, and put into fuel type accounting totals. The variable used to define the regional grid vs self split is the same one used for other cogen accounting in the PMM: CGPCGRDPD(r). In addition, the following new inputs were added to the rfinvest.txt file to help with the cogen accounting.

CHPCC1 = 992   kWh/bbl FOE processed for mode CC1
CHPCO1 = 722   kWh/bbl FOE processed for mode CO1
NGSCHP = 0.10   natural gas fraction fed to CHP

These values *must* be consistent with the KWH and the natural gas coefficients defined in the refproc.dat file in the T:CHP data table.

In addition, a new subroutine (PMM_COKGSF) was created in the refine.f code to transfer model results to report variables. Coke and natural gas consumption, syngas and hydrogen production, and electricity and steam production levels were processed into a PMM report table (48a). The report variables include:

QCOKPRD(3,r,yr)	M s-ton/cd
QASTPRD(3,r,yr)	M bbl FOE/cd
QSGSPRD(r,yr)	M bbl FOE/cd
QHH2PRD(r,yr)	M bbl FOE/cd
QKWHPRD(2,r,yr)	M kWh/cd
QSTMPRD(r,yr)	M lb/cd
QNGSPRD(2,r,yr)	M bbl FOE/cd

Finally, a special algorithm was defined to establish a pet coke export price that better matches historical levels of 45$/ton in 2001 dollars (~6$/bbl FOE in 1987 dollars) and to model an expected 5-10% decline rate. This is currently hard-coded in refine.f, subroutine CHGCKSU. Ultimately, the coke export price should be keyed off of coal prices. This will be designed and incorporated at a later date.

APPENDIX G

Matrix Generator Documentation

APPENDIX G. Matrix Generator Documentation

G.1 Introduction

The purpose of this appendix is to describe the program which generates the 5-region Multi-Refining Model (MRM); and to provide detail on how it works. The program allows the user to simulate a 5-region (MRM) representation of the entire refining industry in the United States in the form of a linear programming (LP) model.

The MRM models multiple refinery regions within the entire United States. The MRM is a collection of five single refinery regions linked by a transportation network. The regions are defined by the five U.S. Petroleum Administration for Defense Districts (PADDs). The MRM simulates the operation of petroleum refineries in the United States, including the supply and transportation of crude oil to refineries, the regional processing of these raw materials into petroleum products, and the distribution of petroleum product to meet regional demands. The model identifies sources of supply for domestic crude oils, alcohols, biofuels, ethers, coal, and natural gas, as well as import levels of crude oil and petroleum products. In addition to these quantities, the MRM projects petroleum product prices, refinery fuel consumption, and capacity expansion in each PADD. The 5-region MRM models the five U.S. PADDs, labeled as follows: E = PADD I, C = PADD II, G = PADD III, M = PADD IV, W = PADD V.

The program generates the matrix for the linear programming model representation of the MRM, solves it, writes the solution, and packs the matrix for use by the analyst using the ANALYZE software.

G.2 Code

The program is written in Fortran and makes use of the OML (Optimization and Modeling Libraries) to read in the data files, to generate the matrix representation of the model, to solve the problem, to store the solution, and to pack the matrix for use with ANALYZE. The program can also produce a report.

The program is data driven and the user provides key information, such as, the model chosen to be run, the location of the input data files, and the names of the output LP and solution files.

G.2.a Variables and Constraints

The model consists of variables or activities (columns), constraints (rows), and bounds on activities and constraints. A unique name has been assigned to each variable and constraint. In the naming of the variables and rows, indices are used. The following table displays the index set name and the number of elements in the set, gives a brief description of the set, and provides a partial listing of the set members.

Index	No. of Values	Description	Members
@	1	represents all regions	@
c	2	Constraint type	X: for max N: for min
d	9	Census divisions	1: New England 2: Mid Atlantic 3: East North Central 4: West North Central 5: South Atlantic 6: Est South Central 7: West South Central 8: Mountain 9: Pacific
e	2	Emission source	C: Emission from fuel combustion N: Emission from process unit (non-combustion)
m	17	Transportation mode, function of material and means of movement	4: U.S. flag residual oil (dirty tanker) 5: Jones-Act crude tanker W: crude pipeline from supply reg 3 to PADD III B: Barge light products (clean barge) I: West Texas to PADD II J: U.S. flag light products (clean tanker) M: Aggregate/avg rail, truck, vessel, barge for ETH O: U.S. flag LPG R: PADD III loop to PADD II S: PADD III capeline to PADD II T: Light product pipeline U: LPG, C4, CC5 pipeline V: Barge residual oil (dirty barge) X: Local transportation Y: Pipeline PADD II to demand region 6 Z: Pseudo link A: LOOP to PADD II
o	7	OGSM regions	1: OGSM 1 North East + OGSM 7 Atlantic 2: OGSM 2 Gulf Coast + OGSM 8 Gulf Offshore 3: OGSM 3 Midcontinent 4: OGSM 4 Permian Basin 5: OGSM 5 Rocky Mountain 6: OGSM 6 West Coast + OGSM 9 Pacific A: OGSM A Alaska North
r	5	Refining regions	E: PADD I C: PADD II G: PADD III M: PADD IV W: PADD V
t	2	Type of transportation	V: Vessel P: Pipeline

Index	No. of Values	Description	Members
x	5	Exporting regions	2: Export cd for PADD I (region E, cd 2)
			3: Export cd for PADD II (region C, cd 3)
			7: Export cd for PADD III (region G, cd 7)
			8: Export cd for PADD IV (region M, cd 8)
			9: Export cd for PADD V (region W, cd 9)
Nn	3	Negative shift in demand	N1, N2, N3
On	8	Natural Gas refinery supply steps	N1, N2, N3, N4, P5, P6, P7, P8
Pn	3	Positive shift in demand	P1, P2, P3
qm	11	Quality code for gasoline blending	AR: Aromatics
			BZ: Benzene
			E2: E 200
			E3: E 300
			M0: Motor octane
			PO: Percent oxygen
			OL: Olefine
			R0: Research octane
			RV: Reid vapor pressure
			SL: Sulfur
			RE: renewables component (due to required minimum contribution to oxygenates)
qd	7	Quality code for distillate	AR: Aromatics
			FL: Flash point
			FZ: Freezing point
			GR: Gravity
			LM: Luminometer number
			SL: Sulfur
			VB: Viscosity
Qs	5	Step label for crude oil imports	Q1, Q2, Q3, Q4, Q5
Rs	9	Step label for product imports	R1, ..., R9
S1	1	Step label for product demands	S1
SX	1	Product exports	SX
Z9	1	Distress imports and exports	Z9
col	5	Coal types availablefor CTL processing	CL1: N. Appalachian
			CL2: Western Montana, Wyoming Powder River Basin, Eastern Interior
			CL3: Rocky Mountain,Wyoming Powder and Green River Basin
			CL4: Dakota Lignite, Powder and Green River Basin
			CL5: Western Montana, Powder and Green River Basin

Index	No. of Values	Description	Members
crt	12	Crude groups by quality and origin	ALL: Alaskan, API 25-66, S<0.5, B<15 AMH: Alaskan, API 21-32, S<1.1, B>15 DLL: Domestic, API 25-66, S<0.5, B<15 DMH: Domestic, API 21-32, S<1.1, B>15 DHL: Domestic, API 29-56, S<1.99, B<15 DHH: Domestic, API 23-35, S<3.0, B>15 DHV: Domestic, API<23, S>0.7, B>15 FLL: Foreign, API 25-66, S<0.5, B<15 FMH: Foreign, API 21-32, S<1.1, B>15 FHL: Foreign API 29-56, S<1.99, B<15 FHH: Foreign, API 23-35, S<3.0, B>15 FHV: Foreign, API<23, S>0.7, B>15
dfo	6	Distillate fuel oil blends	JTA: Jet fuel N2H: Number 2 oil DSL: Low sulfur diesel DSU: Ultra low sulfur diesel N6I: Low sulfur resid N6B: High sulfur resid
emu	6	Emission type	CAR: Total carbon CO1: Carbon monoxide CO2: Carbon dioxide NOX: Nitrous oxides SOX: Sulfur oxides VOC: Volatile organic compounds
ist	833	Refinery intermediate streams	LNI: Light naphtha, (175-250) intermediate LNN: Light naphtha, (175-250) naphthenic LNP: Light naphtha, (175-250) paraffinic
mgb	4	Gasoline blends	TRG: Conventional gasoline RFG: Reformulated gasoline TRH: Conventional high oxygen gasoline RFH: Reformulated high oxygen gasoline
gbt	12	Gasoline blending component type	G01: Butanes (NC4-I4E) G02: Naphthas (NAT-LNN) G03: Reformates (R80-V10) G04: FCC Gasolines (LF6-85H) G05: Other (C5E-R6E,ISO-HRA) G06: HCR Gasolines (LHG-MHV) G07: Alkylates (ALN-HAL) G08: Ethanol (ETH) G09: Ethanol Ethers (TAEE,THEE) G10: Ethylbenzene (ETBE) G11: MTBE (MTB) G12: Methanol Ethers (TAM,THM)
mod	many	Operating mode	C2A: Ethyl alkylate C3A: Propyl alkylate C4A: Butyl alkylate

Index	No. of Values	Description	Members
ncr	12	Non crude purchase	ARB: Atmospheric resid of type B (unf oils) BIM: Biomass diesel (virgin oil, renewable) BIN: Biomass diesel (non virgin oil, renewable) CC3: Propane (gas plant) ETH: Ethanol (renewable) HGM: Heavy gas oil medium sulfur (unf oils) IC4: Isobutane (gas plant) MET: Methanol (methanol plant) MTB: M.T.B.E. (oxygenate) NAT: Natural gasoline (gas plant) NC4: Normal butane (gas plant) NPP: Paraffinic naphtha (unf oils)
pol	34	Policy type	LOS: Lost OVC: Other variable cost MSD: Maximum distillation feed, cat cracker MSR: Maximum low sulfur resid, cat cracker SVR: Maximum severity, cat cracker H00: Maximum 100 severity, HP reformer H05: Maximum 105 severity, HP reformer
prd	20	Products	AST: Asphalt COK: Coke DSL: Low sulfur diesel DSU: Ultra low sulfur diesel E85: 74% Ethanol and 26% TRG JTA: Jet fuel KER: Kerosene LPG: Liquefied petroleum gas M85: 85% Methanol and 15% TRG N2H: Number 2 oil N67: Low sulfur resid to utilities N68: High sulfur resid to utilities N6B: High sulfur resid N6I: Low sulfur resid OTH: Other PCF: Petrochemical feed stock RFG: Reformulated gasoline RFH: Reformulated high oxygen gasoline TRG: Conventional gasoline TRH: Conventional high oxygen gasoline
pri	14	Product imports	DSL, DSU, JTA, LPG, MET, MTB, N2H, N6B, N6I, OTH, PCF, RFG, TRG, SSR
prx	11	Product exports	COK, DSL, DSU, JTA, LPG, N2H, N6B, N6I, OTH, PCF, TRG (and AST in Padd V)
px9	17	Distress exports	AST, COK, DSL, DSU, JTA, LPG, N2H, N67, N68, N6B, N6I, OTH, PCF, RFG, RFH, TRG, TRH
pi9	19	Distress imports	AST, COK, DSL, DSU, E85, JTA, LPG, M85, N2H, N67, N68, N6B, N6I, OTH, PCF, RFG, RFH, TRG, TRH

Index	No. of Values	Description	Members
ss	3	Sub-Spec Products	SSR: Sub-spec Reformulated gasoline (RBOB)
			SST: Sub-spec High Oxygenate gasoline BOB
			SSE: Sub-spec Conventional gasoline TBOB
unf	3	Unfinished oil	ARB: Atmospheric residual bottom type B
			HGM: Heavy gas oil medium sulfur
			NPP: Medium naphtha paraffin
uns	87 (mrm)	Process unit	ACU: Atmospheric crude distillation
			See Appendix A.3.9 for complete list of processes
uuu	3	Utility	KWH: Kilo-watt hour
			NGF: Natural gas liquids
			STM: Steam

In the naming of the columns and rows, the limit is a maximum of eight characters per name. The following two tables give the name of the variable (activity) and the row (constraint) represented.

The general name structure for columns is (v)(r)(abc)(def), where v is key code, r is region code, abc and def are 3 character names.

Name	Activity Represented
B(r)(mgb)(ist)	Blend stream (ist) to gasoline grade (mgb) in (r)
C(d)ETCR(s)	Ethanol from cellulose supply step (s) in (d)
C(d)ETHR(s)	Ethanol from corn supply step (s) in (d)
C(d)BIMR(s)	Virgin oil biomas diesel supply step (s) in (d)
C(d)BINR(s)	NonVirgin oil biomas diesel supply step (s) in (d)
D@METS1	Total US chemical methanol demand
D(d)(prd)S1	Product (prd) demand in (d)
D(d)(prx)SX	Product (prx) exports from (d)
D(d)(px9)Z9	Distress product (px9) export from (d)
E(r)(uns)INV	Investment in new capacity for process (uns) in (r)
F(r)(dfo)(ist)	Blend stream (ist) to distillate fuel oil (dfo) in (r)
G(r)(ist)(prd)	Gas plant output transfer of stream (ist) to product (prd) in (r)
G(r)DGR	Dry gas exiting gas plant in (r)
G(r)GPL01	Gas plant operations in (r)
G(r)(ist)RFN	Transfer of gas plant stream (ist) to refinery in (r)

Name	Activity Represented
G(r)RFNMET	Transfer of methanol from refinery to meet export demands in refinery in (r)
G(r)SC2CC1	Shift of ethane to natural gas in gas plant in (r)
G(r)SC3CC1	Shift of propane to natural gas in gas plant in (r)
G(r)MOH01	Methanol plant operations in (r)
G(r)METDEM	Methanol production from methanol plant in (r) to chemical industry
G(r)METRFN	Methanol production from methanol plant in (r) to refinery
H(r)(uns)(mod)	Production from process (uns) in operating mode (mod) at merchant, CTL, or GTL plant in (r)
H(r)(aa)(bb)(ist)*	Transfer from (aa) to (bb) of stream (ist) in (r)
H(r)KWHMCH	Electricity purchased by merchant units in (r)
I(d)(pi9)Z9	Distress product (pi9) imports to (d)
I(r)(pri)R(s)	Imported product (pri) step (s) to region (r)
J(d)DSUDSU J(d)DSLDSL	Quantity of diesel product not splash blended with biodiesel in (d)
K(r)(uns)CAP	Existing capacity for process (uns) in (r)
L(r)(uns)BLD	Cumulative addition to capacity for process (uns) in (r)
N(r)DGP	Dry gas supply in (r)
N(r)(col)N(s)	Coal (col) supply curve step (s) for CTL processing for region (r)
N(r)NGKN(s)	Alaska NG supply curve step (s) for GTL processing for region (r)
N(r)NGRF(On)	Natural gas to refinery supply step (On) in (r)
NZAMH(On)	Export supply step (On) for Alaskan crude (6 steps only)
O@CRDEXP	Alaskan crude exports
O@CRDSPR	SPR fill in US
P(o)DCRQ1	Domestic crude in (o)
P(r)(crt)(Qs)	Supply step (Qs) of imported crude (crt) to (r)
PANGLQ1	Supply of natural gas liquids from Alaska North slope
Q(r)(mgb), Q(r)(ss)	Spec vector, total volume of (mgb) or (ss) produced in (r)
Q(r)(dfo)	Spec vector, total volume of (dfo) produced in (r)
R(r)ACU(crt)	Volume of crude (crt) processed by the ACU unit in (r)
R(r)(uns)(mod)	Refinery process (uns) operation for mode (mod) in (r)
R(r)CGNCGN R(r)CGXCGN	Refinery (CGN) and Merchant (CGX) cogeneration plant operation in region (r)

Name	Activity Represented
T(r)(ist)(ist) T(r)(ist)(prd)	transfer of stream (ist) to stream (ist) in (r) ; transfer of stream (ist) to product (prd) in (r)
T@UNFTOT T(r)UNF(ist)	Total unfinished oils in US Unfinished oils from stream (ist) in region (r) [regions E,B only]
TAALLTOT	Total Volume of ALL crude produced in Alaska
TAAMHTOT	Total Volume of AMH crude produced in Alaska
TAAMHXZ	Volume of AMH crude transported from Alaska to Valdez
TAGTLTOT	Total volume of GTL's transported from Alaska N. Slope to Valdez along TAPS
TANSOTOT	Total volume of crude transported from Alaska N. Slope to Valdez along TAPS
T(r)CBNTAX	Carbon tax in (r)
T(r)OVCOBJ	Refinery plant operating variable costs in region (r)
T(r)GPLOVC	Gas pland operating variable costs in region (r)
T(r)MCHOVC	Merchant plant operating variable costs in region (r)
U(r)(uuu)	Utility (uuu) purchased in (r)
VTPC(r)(m)(d)	Crude pipeline transportation capacity from (r) to (d) using mode (m)
VTPL(r)(m)(d)	LPG pipeline transportation capacity from (r) to (d) using mode (m)
VTPP(r)(m)(d) VTPP(d)(m)(r)	Product pipeline transportation capacity from (r) to (d) using mode (m) or from (d) to (r)
VTVC(m)CP	Crude vessel transportation capacity for mode (m)
VTVP(m)CP	Product vessel transportation capacity for mode (m)
WAGTLJ(r)	GTL transportation from Alaska (A) to region (r) using mode J
W(r)(prd)(m)(d) W(r)(ss)(m)(d) W(d')(prd)(m)(d) W(d/)(ss)(m)(d)	Product (prd) or (ss) transportation from (r) to (d) or from (d') to (d), using mode (m)
W(d')(ncr)(m)(d)	Ethanol or Biomas diesel (ncr) transportation from (d') to (d) using mode (m)
X(d)(prd)SPG	Recipe blends of product (prd) for oxygenated fuels and electric utility residual oils in (d)
X(r)(ist)(prd)	Recipe blends of product (prd) from stream (ist) in region (r)
X(d)(ncr)(prd)	Splash blending of (prd) from (ncr) in (d)
X(r)(yyyy)**	Recipe blends (yyyy) in region (r)
Y(o)(crt)(m)(r) Y(r')(crt)(m)(r)	Crude (crt) transportation from (o) to (r) or from (r') to (r), using mode (m)

Name	Activity Represented
Z(d)ETCTAX	Total supply of ethanol from cellulose in (d) for adding tax credit to objective function
Z(d)ETHTAX	Total supply of ethanol from corn in (d) for adding tax credit to objective function
Z(r)FLO(uns)***	Total flow through processing unit (uns) in region (r)
Z(r)RFGOXY	Total OXY in RFG in region (r)
Z@TOTCRD	Total foreign crude imports
ZZAMHTOT	Total export volume of Alaskan crude oil

* : (aa), (bb) = MP, GP, RF, where MP = Merchant plant, GP = Gas plant, RF = Refinery. For (ist), first and last character of (ist).

**: (yyyy) = recipe blends for categories of products such as AST, AVG, GOP, JP5.

***: subset of (uns)= DDS, ETH, ETM, FCC, FUM, KRF, RFH, RFL

The general name structure for rows is: (v)(r)(abc)(def), where v is key code, r is region code, abc and def are 3 character names.

Name	Constraint Represented
A(d)(prd)	Product demand accounting row in (d) for (prd)
A@1YRBLD	New ACU capacity added in a look-ahead year
A(r)(prd)	Refined product (prd) accounting row in (r)
A@AKAEXP	Accounting row for Alaskan crude oil exports from US
A(d)BIMPRD A@BIMPRD	Biomas diesel virgin oil accounting row in (d) and total US (@)
A(d)BINPRD A@BINPRD	Biomas diesel non-virgin oil accounting row in (d) and total US (@)
A(r)CHPCGN	Accounting row for combined heat/power from pet coke gasification in (r)
A@COKEXP	Accounting row for petroleum coke exports from US
A@CRDAKA	Alaskan crude oil accounting row in US
A@CRDDCR	Domestic crude oil accounting row in US
A@CRDEXP	Crude oil export accounting row in US
A(r)CRDFCR A@CRDFCR	Foreign crude oil accounting row in (r) and US
A(r)CRDIMP A@CRDIMP	Total crude imported into region (r) in US Total crude imported into US

Name	Constraint Represented
A@CRDL48	Lower 48 crude oil accounting row in US
A@CRDSPR	SPR crude oil accounting row in US
A@CRDTOT	Total crude oil accounting row in US
A(r)CRX(crt)	Crude oil (crt) accounting row in (r)
A(r)DSLCTI	Average cetane in DSL (low sulfur diesel), in region (r)
A(r)DSUCTI	Average cetane in DSU (ultra-low sulfur diesel), in region (r)
A@ETCPRD	Accounting row for total ethanol from cellulose in US
A@ETHPRD	Accounting row for total ethanol from both corn and cellulose in US
A(d)ETHTAX A(d)ETCTAX	Ethanol tax credit accounting row in (d)
A(d)ETH	Accounting row for ethanol supply from (d) from both corn and cellulose
A@ETHE85	Total E85 produced by refineries in US
A@ETHRFG	Accounting of total ethanol blended into RBOB for RFG in US
A@ETHRFH	Accounting of total ethanol blended into RBOB for RFH in US
A@ETHTRG	Accounting of total ethanol blended into TRG (for SSE) in US
A@ETHTRH	Accounting of total ethanol blended into TBOB for TRH in US
A(r)ETHRFN	Ethanol to refinery accounting row in (r)
A(r)FUEL A@FUEL	Refinery fuel use accounting row in (r) and US
A(r)FUM(xx) A@FUM(xx)	FUM accounting row in (r) for fuel type (xx) and US
A(r)FXOC A@FXOC	Fixed cost accounting row in (r) and US
A(d)GO8(yyy)	Gasoline blending accounting row in (d) for mogas (yyy)
A(r)G(gbt)(xxx) A@G(gbt)(xxx)	Gasoline blend component type (gbt) accounting row in (r) for mogas (xxx); US total
A(r)GAIN A@GAIN	Process gain accounting row in (r) and US
A(r)GPLLPG	Accounting of LPG from gas plant in (r)
A(r)GPLOTH A(r)GPLPCF	Accounting of Natural Gasoline from gas plant in (r) to products OTH, PCF
A(r)INVST A@INVST	Investment accounting row in (r) and US
A@KWHRFN	Accounting of refinery KWH usage in US
A@(xx)FU	Limit on fuel type xx consumed as refinery fuel in US (xx=LPG,OTH,RES,STG)

Name	Constraint Represented
A@METDEM	Methanol demand accounting row in US
A(r)METIMP A@METIMP	Methanol imports accounting row in (r); US total
A@METM85	Accounting of methanol used for M85 splash blending in US
A@METPRD	Methanol production accounting row in US
A(r)METRFN	Accounting of methanol consumption by ETH refinery unit in (r)
A(r)MTBIMP A(@)MTBIMP	MTB refinery imports accounting row in (r) and US
A(r)MTBRFN	MTB refinery imports accounting row in (r)
A@MTBPRD	MTB production accounting row in US
A(r)NGFTOT A@NGFTOT	Natural gas purchase accounting row in (r); US total
A(r)NGLRFN A@NGLRFN	Accounting of NGL transfer from gas plant to refinery in (r); US total
A(r)NGLPRD A@NGLPRD	NGL accounting in (r); US total
A(r)NGSH2P A@NGSH2P	Accounting of NGS consumption by H2P refinery unit in (r); US total
A(r)NGSMER A@NGSMER	Accounting of methanol transfer from methanol plant to refinery in (r); US total
A(r)NGSMET A@NGSMET	Methanol plant production accounting row in (r); US total
A(r)NGSRFN	Accounting of purchased NG to refinery NGS stream in (r)
A(r)PETCOK A@PETCOK	Accounting of high & low sulfur coke production at refinery in (r) and US total
A(x)PRDEXP A@PRDEXP	Product export accounting row in (x) and US total
A@PRDDEM	Accounting of total product demand in US
A(r)PRDIMP A@PRDIMP	Product import accounting row in (r)
A@PRDRFN	Accounting of total product produced at refinery
A(d)RFG(yyy) A(d)TRG(yyy)	Gasoline blending accounting row in (d) for mogas (yyy)
A(r)RFGM00 A(r)RFGR00	Total motor (and research) octane in the reformulated (RFG) mogas stream in refining region (r), based on contribution from each component blend stream.
A(r)TRGM00 A(r)TRGR00	Total motor (and research) octane in the conventional (TRG) mogas stream in refining region (r), based on contribution from each component blend stream.

Name	Constraint Represented
A(r)SULSAL A@SULSAL	Accounting of sulfur production in (r) and US total
A(r)UNFIMP A@UNFIMP	Unfinished oil imports into (r) and US total
A@ZZEXP	Total distress exports
A@ZZIMP	Total distress imports
B(r)(ist)	Balance for intermediate stream (ist) in (r)
C(o)(crt)	Crude balance for crude type (crt) in (o)
C(r)(crt)	Crude balance for crude type (crt) in (r)
CAALLTOT CAAMHTOT	Balance for Alaska crude type ALL and AMH
C@ETHBIO	Minimum renewables requirement in gasoline (national)
C(r)CTLTOT	Balance for CTL's produced in region (r)
CAGTLTOT	Balance for GTL's produced in Alaska
CANSOTOT	Balance for Alaska N. Slope crude
C(r)GTL	Balance for GTL's transported from Alaska to region (r)
CZAMH	Alaskan crude exports
D(d)(prd)	Final demand for product (prd) in (d)
D(d)ETH D(d)BIM D(d)BIN	Final supply of renewables ETH, BIM, BIN in (d)
D@MET	Total demand for methanol
D(d)SSL, D(d)SSU	Balance for diesel fuel supply (DSL, DSU) to blended and unblended product in (d)
E(r)(emu)(e)	Emission of (emu) from source (e) in (r)
E/2CTXNBX	Balance to set Mansfield-Blackman national penetration rate (upper limit on build) for CTL units
F@TOTCRD	Total crude balance for unfinished oil constraint in US
F(r)UNF(unf)	Unfinished oil balance for (unf) in (r)
G(r)(ist)	Gas plant balance for stream (ist) in (r)
G(r)(pol)	Gas plant policy (pol) accounting row in (r)
G(r)PGSLGX	Limit on transfer of PGS to LPG at Gas Plant in (r)
G(r)SC2C1X	Limit on transfer of CC2 to CC1 at Gas Plant in (r)
H(r)(ist)	Merchant oxygenate plant balance row for (ist) in (r)

Name	Constraint Represented
	and off-site GTL and CTL balance row for (ist) in (r)
H(r)FUMCAP	Merchant oxygenate fuel balance row in (r)
H(r)(pol)	Merchant oxygenate plant policy (pol) or utility (uuu) accounting row in (r)
H(r)(uuu)	(pol) = stm, kwh, los, ovc
L(r)(uns)CAP	Process (uns) capacity in (r)
M(r)(prd)	Final product (prd) demand balance at refinery (r)
M(d)(prd)	or CD (d)
M(r)MTBRFG	MTBE (and other ethers) limit in RFG motor gasolines in (r)
M(r)MTBTRG	MTBE (and other ethers) limit in TRG motor gasolines in (r)
O(o)(crt)	Domestic crude oil (crt) accounting in (o)
OBJ	Objective function
P(r)(pol)	Policy (pol) constraint in (r)
P(r)CBNTAX	Carbon tax accounting row in (r)
Q(r)(prd)(qd)(c)	Product (prd) specification for quality (qd) constraint type (c) in (r)
Q(r)(prd)(qm)(c)	Product (prd) specification for quality (qm) constraint type (c) in (r)
S(r)(mgb)E	Balance row for blending gasolines (mgb) in (r)
S(r)(dfo)E	Balance row for blending fuel oils (dfo) in (r)
S(r)RFGOXY	Constraint on renewable OXY limits in (r)
TANGKGTX	Maximum NG production in Alaska for GTL use
TAOILGTN	Minimum flow requirement on TAPS in Alaska
TAOILGTX	Maximum flow requirement on TAPS in Alaska
TPC(r)(m)(d)	Crude pipeline transportation capacity balance row from (r) to (d) mode type (m)
TPL(r)(m)(d)	LPG pipeline transportation capacity balance row (r) to (d) mode type (m)
TPP(r)(m)(d)	Product pipeline transportation capacity balance row (r) to (d) mode type (m)
TVC(m)CP	Crude oil vessel transportation capacity limits for mode (m)
TVP(m)CP	Product vessel transportation capacity limits for mode (m)
U(r)(uuu)	Utilities (uuu) in region (r)
Z(r)CAP(uns)	Balance row for total capacity of (uns) in (r)
Z(r)NGFSUM	Sum row for natural gas to refineries in (r)
ZZAMHSUM	Sum row for Alaskan crude export
Z@FLLIMP	Set lower limit on national import level for FLL crude
Z@WOP	Current world oil price in value of RHS
Z@CRDTOT	Sum row for total crude in US

Name	Constraint Represented
Z@YRITER	Iteration year
Z@IRACX	Sum row to force average refinery crude cost within specified range
Z@IRACN	Sum row to force average refinery crude cost within specified range
ZD(mmddyy)	Month, day, year of matrix generation

(I) = 00, 01, 02, ... , 12

(xx) = LPG, N2H, N6B, N6I, NGS, OTH, STG

(xxx) = TRG and RFG

(yyy) = TRG, TRH, and/or RFG, RFH

The following Table gives the dimensions of the MRM model:

Model	Columns			Rows		
	Total	Fixed	Bound Upper Lower	Total	Fixed	RHS
MRM (5 regions)	18954	777	1643 15	6786	5475	27

G.2.b Subroutines

The program consists of several subroutines and a main program. The subroutines can be grouped as those that setup the OML environment, read in the data tables, form parts of the matrix representation of the model, solve the model, retrieve needed information for report writing, and write the reports. All the subroutines that generate part of the matrix representation of the model use input from data files in an OML format. These files have a .dat extension. Some subroutines use ASCII files as input and some others do not use any. The following table shows the subroutine names, the input data file names, and the purpose of the subroutines.

Source Code	Data file	Purpose
accunit.f	accunit.dat	Represents ACU unit
akaexp.f	akaexp.dat	Represents Alaskan exports
avoids.f	avoids.dat	Represents the avoids (not used)
cogener.f	cogener.dat	Represents the cogeneration
crdimprt.f	crdimprt.dat	Represents crude imports
demand.f	demand.dat	Represents demands
distblnd.f	distblnd.dat	Represents distillate blending
distress.f	distress.dat	Represents the distress imports and exports
domcrude.f	domcrude.dat	Represents crude inputs
emish.f	emish.dat	Represents emissions
ethanol.f	ethanol.dat	Represents ethanol supply and prices
fixcol.f	fixcol.dat	Fixes some columns (not used)
fuelmix.f	fuelmix.dat	Simulates fuel mixing
gasoblnd.f	gasoblnd.dat	Simulates gasoline blending
limpol.f	limpol.dat	Puts limits on policy rows (not used)
lplookup.f		Retrieves solution
mrm.f	mrmparam, mrmpath refmain.dat	Program MPS2ANAL: Sets up the OML environment, reads in some main data, controls the program, calls subroutines to form matrix, solves problem, stores solution, writes reports, basis and packs matrix.
mchproc.f	mchproc.dat	Simulates the merchant plant
ngprod.f	ngprod.dat	Provides gas supply steps to refinery
nrfplant.f	nrfplant.dat	Simulates the non refinery plant activities
output.f		Prints a report (not used)
prdexp.f	prdexp.dat	Simulates the product exports
prdimprt.f	prdimprt.dat	Simulates the product imports
recipes.f	recipes.dat	Specifies product recipe blends

Source Code	Data file	Purpose
refproc.f	refproc.dat	Simulates the refinery
setrows.f	setrows.dat	Sets some rows
splash.f	splash.dat	Simulates splash blending
stream.f	stream.dat	Simulates stream transfers
tabread.f		Reads data tables
transit5.f	transit.dat	Simulates the product and crude oil transportation for the 3-region representation of MRM
unfinished.f	unfinish.dat	Provide for unfinished oil imports
utility.f	utility.dat	Simulates utility purchased

Most of the subroutines that constitute the program generate part of the matrix representation of the model. The following gives a representation of the submatrix generated by each subroutine in table form. Columns of the tables correspond to activities (variables), and rows of the tables to constraints. The symbols x, -x or +-x represent matrix coefficients.

accunit.f: This subroutine simulates the ACU unit. It creates the following submatrix:

	R(r)ACU(crt)
A(r)CRDFCR*	x
A(r)STM	-x
A@CRDFCR*	x
A(r)CRX(crt)	x
A@CRDTOT	x
B(r)(ist)	+-x
C(r)(crt)	-x
F@TOTCRD	x
L(r)ACUCAP	x
P(r)(pol)**	+-x
U(r)(uuu)	-x
Z@CRDTOT*	x

* for (crt) = FLL, FMH, FHL, FHH, and FHV
** for (pol) = OVC, FRL

Bounds: None

akaexp.f: This subroutine simulates the Alaskan exports. It creates the following submatrix:

	NZAMH(i)	ZZAMHTOT	TAAMHXZ	PANGLQ1
OBJ	+-x*	x	-x	-x
CAAMH			-x	
CZAMH		-x	x	
BW(ist)				x
ZZAMHSUM	x	-x		
A@AKAEXP		x		
A@CRDEXP		x		
AANGLPRD				x
A@NGLPRD				x
AWNGLRFN				x

(i) = N1, N2, N3, P4, P5, P6
* : -x if i = N1, N2, N3; x if i = P4, P5, P6

Bounds: PANGLQ1, NZAMH(i)

avoids.f: This subroutine simulates the avoids. It is turned off. It creates the following submatrix:

	D(d)(prd)N(i)	D(d)(prd)P(i)
D(d)(prd)	x	-x
A(d)(prd)	-x	x
A@PRDDEM	-x	x
A@AVDNEG	x	
A@AVDPOS		x

(i) = 1, ..., 3

Bounds: D(d)(prd)N(i) and D(d)(prd)P(i)

cogener.f: This subroutine simulates the cogeneration unit. It creates the following submatrix

	E(r)CGNINV	K(r)CGNCAP	L(r)CGNBLD	R(r)CGNCGN
B(r)FUL				-x
L(r)CGNCAP	-x	-x	-x	x
OBJ	-x		-x	x
P(r)OVC				-x
U(r)(uuu)				x
A@FXOC	x		x	
A(r)FXOC	x		x	
A@INVST	x			
A(r)INVST	x			
A@KWHRFN				x

	E(r)CGXINV	K(r)CGXCAP	L(r)CGXBLD	R(r)CGXCGN	R(r)CHP(mod)
B(r)FUL				-x	
L(r)CGXCAP	-x	-x	-x	x	
OBJ	-x		-x	x	x
P(r)OVC				-x	
U(r)(uuu)				x	x
A@FXOC	x		x		
A(r)FXOC	x		x		
A@INVST	x				
A(r)INVST	x				
A@KWHRFN				x	x
A(r)CHPCGN					x

Bounds: E(r)CGNINV, K(r)CGNCAP, L(r)CGNBLD, E(r)CGXINV, K(r)CGXCAP, L(r)CGXBLD

crdimprt.f: This subroutine simulates the crude imports into the United States. It creates the following matrix:

	P(r)(crt)(Qs)
C(r)(crt)	x
OBJ	-x
Z@IRACN	x
Z@IRACX	x
A(r)CRDIMP*	x
A@CRDIMP	x
Z@FLLIMP**	x

(Qs) = supply step Q1,Q2,Q3
* (r)= PADDS II and IV only; **(crt)=FLL only
RHS: A(r)CRDIMP A@CRDIMP Z@FLLIMP
Bounds: P(r)(crt)Q(s)

demand.f: This subroutine simulates product demands. It creates the following submatrix:

	D(d)(prd)S1	D@METS1
D(d)(prd)	-x	
OBJ	x	
A(d)(prd)*	x	
A@METDEM		x
A@PRDDEM	x	
D@MET		-x

* for (prd) not equal to E85 or M85

Bounds: D@METS1 and D(r)(prd)S1

distblnd.f: This subroutine simulates the distillate blending. It creates the following matrix:

	F(r)(dfo)(ist)	Q(r)(prd)*
A(r)(prd)*		x
A(r)STM		-x
A@PRDRFN		x
B(r)(ist)	+-x	

	F(r)(dfo)(ist)	Q(r)(prd)*
M(r)(prd)*		x
Q(r)(prd)*(qd)(c)	+-x	-x
S(r)(dfo)E	x	-x
U(r)STM		-x
A(r)(dfo)CTI**	x	

* (prd) = (dfo) only
** (dfo) = DSL, DSU only

Bounds: None

distress.f: This subroutine simulates product distresses. It creates the following submatrix:

	I(d)(pi9)Z9	D(d)(px9)Z9
OBJ	-x	+-x
D(d)(pi9)	x	
A@ZZIMP	x	
D(d)(px9)		-x
A@ZZEXP		x

Bounds: None

domcrude.f: This subroutine simulates domestic crudes. It creates the following submatrix:

	P(o)DCRQ1	PADCRQ1	TAALLTOT	TAAMHTOT	O@CRDEXP	O@CRDSPR
OBJ	-x	-x				
C(o)(crt)	x					
CAALLTOT		x	-x			
CAAMHTOT		x		-x		
CAALL			x			
CAAMH				x		
CBFHL						-x
A@CRDDCR	x	x				
A@CRDAKA		x				
A@CRDL48	x					
A@CRDEXP					x	

	P(o)DCRQ1	PADCRQ1	TAALLTOT	TAAMHTOT	O@CRDEXP	O@CRDSPR
A@CRDSPR						x
A@CRDFCR						x
O(o)(crt)	x	x				

(o) : except A
Bounds: P(o)DCRQ1, PADCRQ1, O@CRDEXP, O@CRDSPR

emish.f: This subroutine simulates emissions. It creates the following submatrix:

	K(r)(uns)CAP	R(r)FUM(ist)
E(r)(emu)N	x	
E(r)(emu)C		x

where, uns = FCC, VBR, VCU, KRF
Bounds: None

ethanol.f: This subroutine represents ethanol supply and prices. It creates the following submatrix:

	C(d)ETCR(i)	Z(d)ETCTAX	C(d)ETHR(i)	Z(d)ETHTAX	X(d)ETHE85
D(d)ETH	x		x		
OBJ	-x	x	-x	x	-x
A(d)ETH	x		x		
A(d)ETHTAX			x	-x	
A@ETHPRD	x		x		
A(d)ETCTAX	x	-x			
A@ETCPRD	x				
D(d)BIM					
C@ETHBIO	x		x		
A(d)BIMPRD					

ethanol.f (Continued)

	C(d)BIMR(i)	C(d)BINR(i)
OBJ	-x	-x
A(d)BINPRD		x
A@BINPRD		x

	C(d)BIMR(i)	C(d)BINR(i)
D(d)BIN		x
D(d)BIM	x	
C@ETHBIO	x	
A(d)BIMPRD	x	
A@BIMPRD	x	

i = 1, ..., 4
Bounds: C(d)ETHR(i), C(d)ETCR(i), C(d)BIMR(i), C(d)BINR(I)
RHS: row C@ETHBIO; A@ETCPRD

fixcols.f: This subroutine fixes some variables or activity. No submatrix is generated

Bounds: R(r)FCC(ist)

fuelmix.f: This subroutine simulates fuel mixing. It creates the following submatrix:

	R(r)FUM(mod)	T(r)CBNTAX	K(r)FUMCAP
OBJ		-x	
P(r)CBNTAX		x	
A(r)FUM(xxx)	x		
A@FUM(xxx)	x		
A(r)FUEL			x
A@FUEL			x

(xxx) = fuel type, LPG, OTH, N2H, NGS, STG, N6I, N6B
Bounds: None

gasoblnd.f: This subroutine simulates gasoline blending. It creates the following submatrix:

	B(r)(mgb)(ist)	Q(r)(mgb)	Q®(dfo)	Z(r)RFGOXY
OBJ		-x	-x	
A(r)(xxx)(mgb)	x			
A@(xxx)(mgb)	x			
A(r)(prd)*		x		
A@PRDRFN		x		
A(r)(mgb)M00	x			
A(r)(mgb)R00	x			
B(r)(ist)	-x			
M(r)(prd)		x		

	B(r)(mgb)(ist)	Q(r)(mgb)	Q®(dfo)	Z(r)RFGOXY
M(r)MTB(mgb)	x **			
Q(r)RFGREN				-x
Q(r)(mgb)(qq)(c)	x	-x		
S(r)(mgb)E	x	-x		
S(r)RFGOXY				-x
U(r)KWH		-x		

* (prd) = (mgb) only; **ist=MTB,ETB,TAE,TAM,THE,THM only; (xxx) = GO1, ..., G12

Bounds: B(r)RFG(ist) and B(r)TRG(ist) where ist= ETB, MTB, TAE, TAM, THE, THM

limpol.f: This subroutine defines policy conditions. It creates the following submatrix:

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	Z(r)FLO(uns)
Z(r)CAP(uns)	x	x	x	-x
P(r)(pol)				-x

(uns) = specific units underpolicy controls (FCC, KRF, RFH, RFL, DDS, ETH, ETM, FUM)

Bounds: None

lplookup.f: Retrieves solution values and stores them in arrays.

mrm.f: (main)This subroutine reads in the mrmparam file that has the information relative to the model to run; initializes the OML subroutine library environment; opens the database; specifies a problem in the database for processing; initializes the matrix processing; reads in the path file, the main.dat file that contains some global variables such as the refinery, the exporting, and demand regions code; calls the subroutines that generate the matrix; ends the matrix processing; writes out the MPS file; inserts the advanced basis; solves the matrix; puts the solution in output; writes the optimal basis; prints reports; packs the matrix; and closes the database.**mchproc.f:**   This subroutine represents the merchant plant. It creates the following submatrix

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	T(r)MCHOVC	E@CTXINV
L(r)(uns)CAP	-x	-x	-x		
OBJ		-x	-x	-x	
H(r)OVC				x	
A@FXOC		x	x		
A(r)FXOC		x	x		

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	T(r)MCHOVC	E@CTXINV
A@INVST		x			
A(r)INVST		x			
E@CTXMBX		-x***			x

mchproc.f (Continued)

	H(r)(uns)(mod)	H(r)FUX(mod)	K(r)FUXCAP	H(r)KWHMCH	H(r)(aa)(bb)(ist)*
H(r)(ist)	+-x	-x			+-x
H(r)(uuu)	+-x	+x			
H(r)(pol)	+-x	+x			
G(r)(ist)					+-x
B(r)(ist)					+-x
H(r)KWH				x	
H(r)OVC	-x				
A@MTBPRD	x**				
A@NGLPRD					x
OBJ	x			-x	-x
H(r)FUMCAP		x	-x		
L(r)(uns)CAP	x				

mchproc.f (Continued)

	TANSOTOT	TAGTLTOT	N(r)NGKN(s)	N(r)(col)N(s)	H(r)(aa)(bb)(ist)*
OBJ			-x	-x	
H(r)(ist)			x		
H(r)(col)				x	
TANGKGTX			x		
TAOILGTN	x	x			
TAOILGTX	x	x			
CAAMH		x			
CAGTLTOT		-x			x
CANSOTOT		-x			
C(r)CTLTOT					x
C(r)GTL					-x

*: first and last character of (ist); (aa) and (bb) = MP, GP, RF
   where MP = Merchant plant, GP = Gas plant, and RF = Refinery
** for uns=ETX and mod=ETM,MTB
*** for uns=CTX
Bounds: K(r)(uns)CAP, E(r)(uns)INV, L(r)(uns)BLD, H(r)GPMP(ist) and H(r)RFMP(ist) = 0;
N(r)NGKN(s), N(r)(col)N(s)
RHS: rows TANGKGTX, TAOILGTN, TAOILGTX, A@MTBPRD

ngprod.f: This subroutine represents the gas supply steps to refinery. It creates the following submatrix

	N(r)NGRF(ij)*
OBJ	+-x**
Z(r)NGFSUM	x

* (ij) = N1, N2, N3, N4, P5, P6, P7, P8
** +x for N1, N2, N3, N4 and -x for P5, P6, P7, P8

Bounds: N(r)NGRF(ij)

nrfplant.f: This subroutine simulates the non refinery plant. It creates the following submatrix:

	G(r)DGR	G(r)GPL01	T(r)GPLOVC	N(r)DGP	G(r)SC2CC1	G(r)PGSLPG
G(r)OVC	-x		x			
G(r)DGP	x	-x				
G(r)LOS	-x	-x				
G(r)(xxx)		x				
G(r)CC1	-x			x		
OBJ			-x			
G(r)SC2C1X		-x			x	
G(r)PGSLGX		-x				x

nrfplant.f (Continued)

	G(r)NATOTH	G(r)(ist)PCF****	G(r)(xxx)*LPG	G(r)(xxx)**RFN
G(r)(xxx)	-x	-x	-x	-x
OBJ	-x	-x	-x	-x
A(r)GPL(xxx)***	x	x	x	
A(r)NGLRFN				x
A@NGLRFN				x

	G(r)NATOTH	G(r)(ist)PCF****	G(r)(xxx)*LPG	G(r)(xxx)**RFN
B(r)(xxx)**				x
M(r)(prd)***	x	x	x	
A(r)NGLPRD	x	x	x	x
A@NGLPRD	x	x	x	x

nrfplant.f (Continued)

	G(r)SC2CC1	G(r)SC3CC1	G(r)METRFN	G(r)METDEM	G(r)RFNMET
G(r)CC1	x	x			
G(r)CC3		-x			
G(r)LOS	x	x			
G(r)PGS	-x				
OBJ	x	x	-x	-x	
A(r)NGSMER			x		
A@NGSMER			x		
B(r)MET			x		-x
G(r)MET			-x	-x	x
D@MET				x	

nrfplant.f (Continued)

	E(r)MOHINV	L(r)MOHBLD	K(r)MOHCAP	G(r)MOH01
L(r)MOHCAP	-x	-x	-x	x
G(r)MET				x
G(r)OVC				-x
U(r)NGF				-x
U(r)KWH				-x
A(r)NGSMET				x
A@NGSMET				x
A@METPRD				x
OBJ	-x	-x		
A(r)INVST	x			
A@INVST	x			
A(r)FXOC	x	x		
A@FXOC	x	x		

(xxx) : PGS, CC3, IC4, NC4, NAT
* : (xxx) except NAT ; **: (xxx) except PGS, CC3;
*** LPG, OTH, PCF; **** ist = NAT, PGS

Bounds: G(r)SC3CC1, N(r)DGP, E(r)MOHINV, K(r)MOHCAP, L(r)MOHBLD

output.f: This subroutine prints reports.

prdexp.f: Simulates product exports. It creates the following submatrix:

	D(z)(prx)*SX	D(z)COKSX	D(z)ASTSX
D(z)(prx)	-x	-x	-x**
OBJ	x	x	
A@COKEXP		x	
A(d)PRDEXP	x		x**
A@PRDEXP	x		x**

*: All (prx) except COK and AST; (z) = export demand regions (d) 2,3,7,8,9
**: d = z = CD 9 only

Bounds: D(z)(prx)SX, except for (prx) = COK
RHS: A@COKEXP

prdimprt.f :   This subroutine simulates product imports. It creates the following submatrix:

	I(r)(pri)*R(s)	I(r)(pri)**R(s)	I(r)SSRR(s)
A@(pri)*IMP	x		
A(r)(pri)*IMP	x		
B(r)(pri)*	x		
A(r)(pri)RFN	x***		
A(r)PRDIMP		x	
A@PRDIMP		x	
M(r)(pri)**		x	
OBJ	-x	-x	
A(r)SSRIMP			x****

* : for (pri) = MET and MTB; **: for all (pri) except MET and MTB;
*** for (pri) = MTB only; **** (r) = PADD I only (E)
(s) = product import steps 1-9

RHS: A@PRDIMP, A(r)PRDIMP [(r) = PADD's II, IV only], A(r)SSRIMP [(r) = PADD I only]
Bounds: I(r)(pri)R(s)

recipes.f: This subroutine simulates product recipe blending. It creates the following submatrix:

	X(r)(xxx)(yyy)	X(r)(yyyy)
B(r)(ist)	-x	-x
M(r)(yyy)	x***	x
OBJ	x	-x*
U(r)STM		-x**
A(r)STM		-x**
A(r)(yyy)	x***	x
A(r)SULSAL	x****	
A@SULSAL	x****	
A(r)PETCOK	x***	
A@PETCOK	x***	
A@PRDRFN	x***	x

(xxx) = AST, AVG, CKH, CKL, GOP, SUL ; (yyy) = AST, OTH, COK, PCF, SAL
(yyyy) = AST0, AST1, AVG0, GOP0;
: for (yyyy) = AVG; **: for (yyyy) = AST0; ***: for (yyy) = COK; **** for (yyy) = SAL

refproc.f: This subroutine simulates the refinery processes. It creates the following submatrix:

	E(r)(uns)INV	K(r)(uns)CAP	L(r)(uns)BLD	T(r)OVCOBJ	R(r)(uns)(mod)
OBJ	-x		-x	-x	
A@1YRBLD	x*******				
A(r)INVST	x				
A@INVST	x				
A(r)FXOC	x		x		
A@FXOC	x		x		
A(r)GAIN					+-x
A@GAIN					+-x
A(r)METRFN					x**
A(r)NGSH2P					x***
A@NGSH2P					x***

	E(r)(uns)INV	K(r)(uns)CAP	L(r)(uns)BLD	T(r)OVCOBJ	R(r)(uns)(mod)
A@MTBPRD					x****
A(r)STM					-x
A@(fff)FU					x*****
B(r)(ist)					+-x
L(r)(uns)CAP	-x	-x	-x		x
M(r)(prd)******					-x
P(r)(pol)				x*	+-x
P(r)CBNTAX*****					-x*****
U(r)(uuu)					+-x

*: (pol)=OVC; **: (uns)=ETH; ***: (uns)=H2P; ****: (uns)=ETH and (mod) = MTB;
*****: (uns)=FUM only; ******: (prd)=N6I, N6B only; (fff)=LPG, STG, RES, OTH;
*******: (uns) = ACU only

Bounds: K(r)(uns)CAP, E(r)(uns)INV, L(r)(uns)BLD,
    R(r)FUM(mod) where (r)=PADD V only, (mod)=NPI,NPN,NPP,SRC,SRH,SRI,SRL,
    R(r)FCC(mod) where mod = 70H,70M,70U,H70,M70,U70
RHS: rows A@STGFU, A@LPGFU, A@RESFU, A@OTHFU, A@1YRBLD

setrows.f: This subroutine sets the row types (G, L, E, N) for rows P(r)(pol).

splash.f: This subroutine simulates splash blending. It creates the following submatrix:

	X(d)ETH(xxx)	X(d)METM85	X(d)(www)SPG	Q(r)(mgb)	B(r)RFG(sss)	B(r)RFG(rrr)
D(d)(xxx)	x	-x****				
D(d)ETH	-x					
D(d)(yyy)	-x					
D(d)M85		x				
D(d)MET		-x				
A(d)G08(xxx)	x*					
A@ETH(xxx)	x					
A@METM85		x				
A(d)RFG(xxx)** not linked to col						
A(d)TRG(xxx)	x***					
D(d)(www)			x			
D(d)(ttt)			-x			

	X(d)ETH(xxx)	X(d)METM85	X(d)(www)SPG	Q(r)(mgb)	B(r)RFG(sss)	B(r)RFG(rrr)
Q(r)RFGREN	x**				x	
S(r)RFGOXY	x**					x
M(r)MTB(mgb)				-x		x

	J(d)DS(j)DS(j)	X(d)BINDS(j)	X(d)BIMDS(j)
D(d)DS(j)	x	x	x
D(d)SS(j)	-x	-x	-x
D(d)BIN		-x	
D(d)BIM			-x

(rrr) = ETB, MTB, TAE, TAM, THE, THM; (sss) = ETB, TAE, THE;
(ttt) = N6B, N6I; (www) = N67, N68; (xxx) = E85, RFG, RFH, TRH, TRG;
(yyy)=SSR when (xxx)=RFG, RFH and (yyy)=SST when (xxx)=TRH and
(yyy)=SSE when (xxx)=TRG; (j)=l, u (for DSL, DSU);
*: (xxx) not E85; **: (xxx)=RFG, RFH only;
:(xxx)=TRG, TRH only; *:(xxx)=TRG only
Bounds: none.

stream.f: This subroutine simulates stream transfers. It creates the following submatrix:

	T(r)(ist)(ist)	T(r)(ist)(prd)
B(r)(ist)	+-x	-x
M(r)(prd)		x
A(r)(prd)		x
A@PRDRFN		x

tabread.f: This subroutine prints the data file names, the number of tables and lists the tables names that are read.

transit5.f: This subroutine simulates the transportation network for MRM 3-region

	Y(o)*(crt)(m)(r)	W(d)ETH(m)(r)	W(r)MET(m)(d)	W(s)(prd)(m)(d)	V(xxxxxx)
C(o)(crt)	-x				
C(r)(crt)	x				
OBJ	-x	-x	-x	+-x****	
TPC(o)*(m)(r)	x				-x

	Y(o)*(crt)(m)(r)	W(d)ETH(m)(r)	W(r)MET(m)(d)	W(s)(prd)(m)(d)	V(xxxxxx)
TVC(m)CP	x				-x
TVP(m)CP				x	-x
TPP(s)(m)(d)				x***	-x
TPL(s)(m)(d)				x****	-x
B(r)ETH		x			
D(d)ETH		-x			
D(r)ETH		x**			
A(r)ETHRFN		x			
B(r)MET			-x		
D(d)MET			x		
D(d)(prd)				x	
M(r)(prd)				-x	
M(d)(prd)				x	
(xxxxxx)					-x

transit5.f: (continued)

	Y(o)*(crt)(m)(r)	TANSOTOT	TAAMHXZ	TAGTLTOT	W(d)(nrc)(m)(s)
C(r)GTL					
CANSOTOT	x	-x	x		
OBJ		-x		-x	-x
B(r)(nrc)[*****]					x
D(d)(nrc)[*****]					-x

transit5.f: (continued)

	WAGTLJ(r)	W(s)DS(j)(m)(d)	W(s)BIN(m)(d)	W(s)BIM(m)(d)
C(r)GTL	x			
M(r)(prd)		-x		
OBJ	-x		-x	-x
TVPJCP	x			
D(d)SS(j)		x		
D(d)BIN D(s)BIN			+-x	

	WAGTLJ(r)	W(s)DS(j)(m)(d)	W(s)BIN(m)(d)	W(s)BIM(m)(d)
D(d)BIM D(s)BIM				+-x

(j)=l, u (for DSL, DSU)
* OGSM supply (o) and refinery (r) regions; ** for (r)=Census Division
*** for (prd) different than MET, ETH; **** for (prd) = LPG and PCF;
***** for (nrc) = BIM, BIN only; (s) = refinery (r) and demand (d) regions;
(xxxxxx) = TVC5CP, TVPJCP, ...

Bounds: V(xxxxxx), W(d)ETH(m)(r)

unfinished.f: This subroutine simulates the unfinished oil process. It creates the following submatrix:

	T(r)UNF(ist)	T@UNFTOT	RHS
B(r)(ist)	x		
F(r)UNF(ist)	-x	x	
OBJ	-x		
A(r)UNF	x		
A@UNFIMP	x		
A(r)UNFIMP	x		
F@TOTCRD		-x	x

utility.f: This subroutine represents the utility. It creates the following submatrix:

	U(r)(uuu)	R(r)KWGPGN	T(r)NGFNGS
U(r)(uuu)	x		-x***
OBJ	-x		
A@KWHRFN	x*	x	
B(r)NGS			x
A(r)NGSRFN			x
A@NGFTOT	x***		
A(r)NGFTOT	x***		
Z(r)NGFSUM	-x***		

*: for (uuu) = KWH ;***: for (uuu) = NGF

All the FORTRAN files are located in the directory n:/default/source/ on the EIA NT server.

G.2.c Common Blocks

Variables shared by several subroutines are set up in common. There are four files that contain the common blocks used by the program. Some of the files consist of several common blocks.

The following table lists the common block names, gives a brief description and the location of the block.

Common	Description	Location
IPMMREAL	Common for real variables shared by subroutines that generate submatrices	/default/includes/ipmmtest
IPMMINT	Common for integer variables shared by subroutines that generate submatrices	/default/includes/ipmmtest
IPMMCHAR	Common for character variables shared by subroutines that generate submatrices	/default/includes/ipmmtest
LPTAB	Common used for solution retrieval and report writing	/refine/pmm_lp_gen/includes/lpout
OMLREAL	Common for real variables used to set LP memory size	/default/includes/omlspace
OMLINT	Common for integer variables used to set LP memory size	/default/includes/omlspace
DFINC2	Common for OML database functions	/default/includes/dfinc2
WCR	Common for the WHIZ optimizer	/default/includes/wfinc2

A list of the common blocks and the variables that constitute them is given in Appendix G-D.

G.3 Data

Most of the data that the program uses is provided in files with a .dat extension. There is a one to one correspondence between the FORTRAN files that form part of the matrix and the *.dat* data files (eg, accunit.f gets its input from accunit.dat). In each of the *.dat* files, the data is arranged in an OML format that consists of data tables. Each table consists of a table name, row (or stub) and column (or head) names, and values at the intersection of rows and columns. In addition there are ASCII files. These ASCII files are for control of the program. The following is the description of each input file.

G.3.a Data Sets

.dat files

accunit.dat

Table Name	Columns	Rows	Description
ACUCUTS	(crt)	(ist); FUL	Crude distillation yield
ACUPOL	OVC, LOS	(crt)	ACU policy table
ACUUTI	STM, KWH	(crt)	ACU utility consumption
INVLIM	MAX	(r) , @	Maximum investment

akaexp.dat

Table name	Columns	Rows	Description
EXPAKA	P, Q	N1, N2, N3, P4, P5, P6	Price and quantity of Alaskan crude exports.
NGLAKA	PER	PGS, CC3, NC4, IC4, and NAT	Yield of NGL
PRQAKA	VOL, TRP, EXPPRC	A	Volume, and transportation and expected cost for Alaskan crude exports

avoids.dat   (no longer used)

Table	Columns	Rows	Description
SADELPX	FACTORS	N1, N2, N3, P1, P2, P3	Price differentiate
PRDAVOID	DUMMY	(prd)	Product list
SADELQ	N1, N2, N3, P1, P2, P3	(prd)	Demand shift quality fraction

cogener.dat

Table	Columns	Rows	Description
CGNCAP	CAP, PUL, BLD	(r)	Refinery cogeneration capacity, %utilization and build
CGNINV	INV, FXOC, CAPREC	(r)	Refinery cogeneration investment, fixed cost and capital recovery
CGNPOL	OVC	CGN	Refinery cogeneration policy
CGNREP	CGN	FUL	Refinery cogeneration yields
CGNUTI	(uuu)*	(r)	Refinery cogeneration utility usage
SELCGN	SOLD	(r)	% cogeneration sold to grid from Refinery
VPELAS	(r)	(year)	Electric utility prices for Refinery cogen (87$/kwh)
CGXCAP	CAP, PUL, BLD	(r)	Merchant plant cogeneration capacity, %utilization and build
CGXINV	INV, FXOC, CAPREC	(r)	Merchant plant cogeneration investment, fixed cost and capital recovery
CGXPOL	OVC	CGN	Merchant plant cogeneration policy
CGXREP	CGX	FUL	Merchant plant cogeneration yields
CGXUTI	(uuu)*	(r)	Merchant plant cogeneration utility usage
SELCGX	SOLD	(r)	% cogeneration sold to grid from Merchant plant
VPELWS	(r)	(year)	Electric utility prices for Merchant cogen (87$/kwh)

* except NGF

crdimprt.dat

Table	Columns	Rows	Description
CRUDETYP	DUMMY	(crt)*	Foreign crude types
ICR(crt)*(r)	C1, Q1, C2, Q2, C3, Q3	(year)	Price and quantity available for crude imports.

*: for (crt) = FLL, FMH, FHL, FHH, FHV (i.e. foreign crude only)

demand.dat

Table	Columns	Rows	Description
CKSMIX	CKL, CKH	OBJ, CKL, CKH, COK	Coke price and conversion factor
PRODLIST	DUMMY	(prd)	List of products

Table	Columns	Rows	Description
(prd)*	(d)	(year)	Product (prd) demand
DEMMET	CHEM	(year)	MET demand by Chemical Industry

* RFH mapping and corresponding table renamed to RFHA due to duplicate table name elsewhere.

distblnd.dat

Table	Columns	Rows	Description
Q(r)DFO	(dfo)	(spec)	Distillate fuel oil blend specs
DFOUTI	STM	(dfo)	Distillate blend steam use.
DCC	(dfo)*	(ist)	Distillate recipe blend.
DCB	spec categories **	(ist)	Distillate blend intermediate stream quality specification.

  * from Z:MAPDFOPD
** from Z:MAPDFOSP

distress.dat

Table	Columns	Rows	Description
ZPX	VALUE	(prd)	Distress code for pricing

domcrude.dat

Table	Columns	Rows	Description
DCRSUP	(o)	Y96	Historical crude supplies by OGSM region
DCRSHR	(o)	(crt)*	Domestic crude share by OGSM region
CREXP	CRDEXP, CRDSPR	VOL	Crude exports and SPR

*: (crt) except FLL, FMH, FHL, FHH, FHV

emish.dat

Table	Columns	Rows	Description
EMUNS	(emu)*	Process unit	Emission by process unit
EMFUM	(emu)	Fuel stream burned	Emission by fuel burned

* except CO2

ethanol.dat

Table	Columns	Rows	Description
SUPETH(d)*	C1, R1, C2, R2, C3, R3, C4, R4	(year)	Ethanol supply curves
ETHTAX	TAXETH, TAXE85	(year)	Ethanol taxes; tax subsidy
MINRENEW	USMIN	(year)	Min renewables required in gasoline (US total)
SUPBIM	C1, R1, C2, R2, C3, R3, C4, R4	(d)	Biomas diesel supply curves (virgin oil)
SUPBIN	C1, R1, C2, R2, C3, R3, C4, R4	(d)	Biomas diesel supply curves (non-virgin oil)

* (d) from Z:CDMAP

fixcols.dat   (no longer used)

Table	Columns	Rows	Description
FIXCOL	R	Dummy	First letter of column to fix
(r)RCOL	FCC	(mod)	Column to fix to zero

fuelmix.dat

Table	Columns	Rows	Description
GROUP	DUMMY	Fuel stream	List of fuel stream

gasoblnd.dat

Table	Columns	Rows	Description
Z:MAPGSLPD	ENSYS CODE	TRG, RFG	Map Ensys mogas ID to EIA mogas ID
Z:MAPGSLSP	ENSYS CODE	EIA codes	Map Ensys spec ID to EIA spec ID
Q(r)GSL	TRG, RFG	(spec)	TRG, RFG specs
(r)SSR	Y1, Y2, Y3, Y4, Y5	RFG(spec); YEAR	Gasoline specs for subspec SSR ; year of data
(r)SST	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline specs for subspec SST; year of data
(r)SSE	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline specs for subspec SSE; year of data
(r)RFH	Y1, Y2, Y3, Y4, Y5	RFG(spec); YEAR	Gasoline spec for RFH; year of data
(r)TRH	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline spec for TRH; year of data
Z:GASGROUP	TEXT(1)	(ist)	List of blending streams specially grouped
GCB	Quality codes	(ist)	Gasoline blend intermediate stream quality spec.

Table	Columns	Rows	Description
GCC	Gasoline type	(ist)	Gasoline recipe blend.
MCO	Motor octane codes*	(ist)	Gasoline component base octane ratings
(xxx)BV	Motor octane codes**	(ist)	Gasoline component blending values
GSLUTI	KWH	(prd), SSE, SST, SSR	Gasoline utility use.
GSPETH	RE	RFGN	Gasoline specs for ETH

(spec) = 2 character quality code followed by X (maximum) or N (minimum).
(xxx) = many exist, however, PMM uses UNC and RFM defined by Z:MAPGSLPD (representing TRG and RFG, respectively).
* R00, R05, R15, R30, M00, M05, M15, M30, of which only R00 and M00 are used by the PMM.
** same as *, except column TEL added (but not used by the PMM).

limpol.dat

Table	Columns	Rows	Description
UNITPOL	DUMMY	(uns)	List of processes that have a limit on POL
LIM(uns)(r)	(ist)	DUM	Limit on (ist)

refmain.dat

Table	Columns	Rows	Description
EXPROD	DUMMY	(prx)	List of product exports
INVFACT	LOC, ENV	(r)	Location and environment factors
TRSOVC	OVC	(r)	Year $ conversion factor for operating cost
FORCRD	DUMMY	(crt)*	List of foreign crude
YRDOLLAR	2000	1987	Year $ conversion factor
ZIRACFAC	DELTA	ZIRAC	Range of price differential for IRAC
WOP	WOP	(year)	World oil price (87$)
RFNREG	PAD	(r)	List of refinery regions vs PADD
RFNEXP	RFID	Linked list of refinery and export regions	List of exporting regions
DEMNDREG	REGION	Linked list of refinery and demand regions	List of demand region
USERYEAR	YEAR	Y96	Year to run model

* FFL, FMH, FHL, FHH, FHV

mchproc.dat

Table	Columns	Rows	Description
MCHINV	INV, FXOC, CAPREC	(uns)	Merchant plant investment, fixed cost and capital recovering
(r)CAPMCH	CAP, PUL, BLD	(uns)	Merchant plant processes capacity, % utilization and build.
(uns)POL*	(pol)	(ist)	Merchant plant processes policy
(uns)CAP*	(uns)CAP	(ist)	Merchant plant process capacity
(uns)REP*	(mod)	(ist)	Merchant plant process yields
(uns)UTI*	(uuu)	(ist)	Merchant plant process utility usage
TRANSFER	Dummy	GP, MP, RF	Transfer allowed
RFTRANS	MP	(ist)	Refinery transfer to merchant plant
GPTRANS	MP	(ist)	Gas plant transfer to merchant plant
MPTRANS	GP, RF	(ist)	Merchant plant transfer to gas plant and refinery
MPTRANS1	GTLRF, CTLRF	(ist)**	Merchant plant transfer to refinery
(r)UAP	CST	(uuu)	Utility purchases

* uns defined by T:MCHINV
** (ist) related to GTL and CTL liquid streams

ngprod.dat

Table	Columns	Rows	Description
SPNGF	ALLREG	N1, .., N4, P5, ..., P8	Price steps for gas supply
SQNGF	MAX, MIN	N1, .., N4, P5, ..., P8	Quantity steps for gas supply
SCVAL	(r)	VOL	Volume limits on each step

nrfplant.dat

Table	Columns	Rows	Description
INVMOH	INV, CAPREC, FXOC	MOH	Non refinery plant process investment, capital recovery, and fixed cost.
MOHPLT	(r)01	CC1, MET, OVC, KWH	Production of methanol
MOHCAP	(r)01	CAP	Methanol capacity
GASPLT	(r)01	(ist), (pol)	Yield from gas plant
GASSHFT	SC2, SC3	CC1, LOS, OBJ	Shift of ethane and propane to methane

Table	Columns	Rows	Description
GASCAP	(r)01	FAC, CAP, LIM, PCU	Gas plant capacity limits
CC1CAP	(r)01	(year)	Dry gas production capacity

prdexp.dat

Table	Columns	Rows	Description
(x)PRDEXP	MINY1, MAXY1, MINY2, MAXY2, ... MINY5, MAXY5	(prx), YEAR	Limit on volume to export; year of data
EXPLIM	YRPC, FIX	1995	Limit on volume and yearly increase
MULTEXPR	MULT	PRICE	Price for exports as function of imports

(x) = export regions (CDs 2,3,7,8,9).

prdimprt.dat

Table	Columns	Rows	Description
PRODTYP	DUMMY	(pri)	List of product import
IMPLIM	MAX	@	Maximum imports into USA
IPR(pri)(r)	C1, R1, ..., C9, R9	(year)	Product import supply curve
NEMSRSD	R1B, R1PR	R1, ..., R9	Resid import supply curve

recipes.dat

Table	Columns	Rows	Description
RCPEIA	A, CST, JTA, N2H, SLP, CKH, CKL	KERSPG, SULSAL, CKHCOK, CKLCOK	Cost of sulfur and coke; kerosene split; unit conversions.
RCP	A, CST, component stream, STM	Recipe blended products	Recipe blends (fractions)

refproc.dat

Table	Columns	Rows	Description
(r)CAP	CAP, PUL, BLD	(uns)	CAP, PUL and BLD values
(uns)	(mod)	(ist), (uuu), CAP, (pol)	Refinery process yields, utility usage, capacity factor, policy
MATBAL	A, B	(ist)	Streams requiring material balance
INV	INV, FXOC, CAPREC	(uns)	Refinery processes investment, fixed cost and capital recovery

Table	Columns	Rows	Description
SCL	selected processing units	selected streams/utilities	selected factors applied to selected coeff in T: (uns)

setrows.dat

Table	Columns	Rows	Description
(r)POL	TYPE	(pol)	Row type

splash.dat

Table	Columns	Rows	Description
HOXETH	TRH, RFH, RFG,TRG	Gasoline stream	Ethanol recipe for splash blending
BLBIOD(d)	DSL, DSU	BIN, BIM	Blend composition recipe for biodiesel
BLNSP(d)	KER, N67, N68	JTA, N2H, KER, N6I, N6B, N67, N68	Blend composition recipe
BLOX(d)YXX	E85, M85, TRH, RFH, RFG, TRG	Gasoline stream	Recipe blend composition
XETH	PO	XETH	Oxygen content of ethanol
SCB	PO	Oxygenate stream	Oxygen content of oxygenates

stream.dat

Table	Columns	Rows	Description
XSALE	DUMMY	(ist)(prd)	Linked list of stream transfer to products
TRS	MIN, MAX, CST	(ist)(ist)	Linked list of stream to stream transfers

transit.dat

Table	Columns	Rows	Description
MVCCAP	MAX	TVC(m)CP, TVP(m)CP	Marine vessel capacity for crude & product
BVPCAP	MAX	TVP(m)CP	Marine barge capacity for product
PLCCAP	MAX	TPC(o)(m)(r) TPP(r)**(m)(d) TPL(r)**(m)(d)	Pipeline capacity for (C) crude (P) product (L) LPG
TPCRLIST	DUMMY	(o)	Domestic crude supply regions for transportation
TPCR(o)	(crt); GTL	(m)(r); TAPS	Crude oil transportation cost from domestic supply region (o) to refinery region (r)
PLCRLIST	DUMMY	(o)	List of domestic crude oil supply regions for pipeline

Table	Columns	Rows	Description
PLCR(o)	(crt)	(m)(r)	Crude pipeline transportation cost from (o) to (r)
BVPR(r)	(prd)	(m)(d)	Product barge/truck transportation cost from (r) to (d)
TPPR(r)	(prd)	(m)(d)	Product marine transportation cost from (r) to (d)
TPME(r)	MET	(m)(d)	Methanol transportation cost from (r) to (d)
TPETLIST	DUMMY	(d)	List of Census Divisions for ethanol transportation source
TPET(d)	ETH	(m)(r)**	Ethanol transportation cost from (d) to (r)
PLPRLIST	DUMMY	(d)	List linked census divisions for product pipeline from region B to East Coast
PLPR(r)**	(prd), SSE, SST, SSR	(m)(d)	Product pipeline transportation cost from (r)** to (d)
PLLG(r)**	LPG, PCF	(m)(d)	LPG transportation cost from (r) to (d)
PLNKLIST	DUMMY	(r)**	List of product pipeline originations.
PLNK(r)**	(prd), SSE, SST, SSR	(m)(r)**	Product pipeline transport connections and costs from (r)** to (r)**
TPBDLIST	DUMMY	(d)	List of Census Divisions for biomas diesel transportation source
TPBD(d)	BIN, BIM	(m)(r)	Biomas diesel transportation cost from (r)

** refinery (r) and/or demand (d) regions

unfinish.dat

Table	Columns	Rows	Description
UNFOIL	E, G, W, PD	streams: NPP, HGM, ARB	Types (3) of unfinished oil imports into the U.S.
UNFEQT	SLOPE, CONST	XYZ	eq. parameters that correlate unfinished oil imports to crude input

utility.dat

Table	Columns	Rows	Description
UTITRS	COEF	NGFNGS	BFOE natural gas.
(r)UAP	CST	(uuu)	Utility costs.
VALPNG	(r)	(year)	Industrial price of natural gas.
VPELIN	(r)	(year)	Industrial elec utility prices (87$/kwh)

G.3.b Other input files

1. **mrmparam** file

The mrmparam file is a control file read by mrm.f to map input and output file names and instructions. In the mrmparam, the user chooses the model that he wants to run; the names for the problem, solution, path file, basis, mps file, and packed matrix; the model title; and the location and name of the starting basis and optimal basis. The following table lists the information that is to be supplied in the mrmparam file.

Variable name	Variable length	Variable purpose	Restrictions
MODELN	8	Model to be run	MRM5
ACTPROB	8	Act problem	
SOLNAME	8	Solution name	
PATHNF	7	Name of file where data files paths are stored.	
TITLE	48	Problem title	
INBASISN*	48	Location and name of advanced basis	
OUTBASIS	10	Name of optimal basis	
BASISN	10	Basis name	Must be name in INBASISN file
MPSOUTN**	10	MPS file name	
PAKCN**	10	Packed matrix file name	.PCK extension
TRACE	3	Toggle Trace Utility	

*: If no name or a file does not exist, the program will operate without an advanced basis.
**: if NULL   or   null   is provided, the program will skip the part of the program that generates the file.

The above variables have to be provided in the order they are listed in the above Table and should start at column 18. Appendix G-A provides an example of an mrmparam file. The mrmparam file has to be in the subdirectory where the model is executed.

2. **mrmpath** file:

In this file the user provides the program with the location and name of the data files. The order in which the names appear is important. See Appendix G-B for an example of a path file. The path file has to be in the directory from which the model is executed. This file format is that of an OML table.

3. **Advanced basis** file:

In this file the user provides an advanced basis to the model. If the user does not provide one or provides one whose name does not coincide with the basis name provided in the mrmparam, the program will not use it.

G.4 Submission of a Run

In order to run the model, one has to first compile and link the different FORTRAN source files to form an executable. Once the executable is created, the user submits a run in conjunction with a mrmparam and a mrmpath file. The execution of the program will solve the problem and create:

- An ACTFILE file
- An MPS file
- A SYSPRINT file (solution)
- An out basis file
- A packed matrix file
- Reports (only for MRM5)

The following are the files created by a run:

	MRM
ACTFILE	ACTFILE.act
MPS file	Name provided by user in the mrmparam file
Solution file	SYSPRINT
Out basis	Name provided by user in the mrmparam file
Packed matrix	Name provided by user in the mrmparam file
Report	reports5, fort.75

All the files used for the MRM matrix generation reside within the NEMS default directories on EIA s NEMS NT servers, as defined next. The source files that encompass the program are on n:/default/source/. The user must create and link the object files to form the mrm executable (mrm.exe) to be located in the user s directory. The *Developer's Studio* (a debugging package for the PC) is used by the user to compile, link, execute, debug, and manage files. Instructions on how to use this package, in connection with the mrm, are defined below.

The mrmparam file and the mrmpath file used for the MRM model are located in the n:/default/scripts/ directory. To run the model, the param and path files must be copied to the user's Debug directory. The path files point to the default data files (*.dat) that are stored in n:/default/input/ directory.

<u>Runs</u>

First, connect to the NEMS-F8 via a terminal server client, and open a korn shell. You are now operating within a UNIX environment. All runs will be made using the *Developer's Studio*.

1. Set up and run the default (no changes):

    a. Create a scenario directory in your user directory, then create the following directories within the scenario directory: Source, Data, Debug
    b. In the Debug directory, *nemsco* the default **mrmparam** and **mrmpath** files.
    c. In the scenario directory, *nemsco* mrmmps.dsp (a *Developer's Studio* project file).
    d. Double-click the *Developer's Studio* icon on your NEMS-F8 terminal server desktop.
        -- from the FILE, OPEN menu, set file type to *.dsp, and select the mrmmps.dsp file. (This creates two more files in the scenario directory: mrmmps.dsw and mrmmps.opt.)
        -- from the PROJECT, SETTINGS menu, click on the Debug tab. Highlight the path defined in the "Executable for debug session" display, and copy it to the "Working directory" display just below. HOWEVER, go to the "Working directory" display and delete "\mrmmps.exe" portion of the path just created. Click OK.
    e. To compile and link all default mrm code and DLLs, go to the BUILD menu, and select "Rebuild All." A message will appear in the lower window that the executable has been created. (Note: Lately, a single warning appears, which can be ignored.)
    f. To execute the default, go the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
    g. The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.

2. Make changes to a mrm data file and rerun mrm:

    a. In the Data directory, *nemsco* the data file the user wants to change.
    b. Edit, change, and resave.
    c. In the Debug directory, edit the **mrmpath** file.
        -- modify the path of the updated data file to point to the new location in the Data directory, and resave
        -- delete (remove) the following files that were created from a previous mrm run: mpsnrm.txt, mrmpack, ACTFILE.act, and SYSPRINT
    d. Double-click the *Developer's Studio* icon on your NEMS-F8 terminal server desktop.
        -- from the FILE, OPEN menu, set file type to *.dsw, and select the mrmmps.dsw file from the scenario directory (created in step 1.4 above)
    e. To execute [assuming source code has already been compiled], go the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
    f. The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.
    g. REMEMBER: After a new data file is defaulted, the corresponding data file name in the **mrmpath** file must be updated to map the proper default version. Then, the **mrmpath** file must be defaulted.

3. Make changes to a mrm source code and rerun mrm:

    a.   In the Source directory, *nemsco* the source code one wants to change.
    b.   Edit, change, and resave.
    c.   In the Debug directory, delete (remove) the following files that were created from a previous mrm run: mpsnrm.txt, mrmpack, ACTFILE.act and SYSPRINT
    d.   Double-click the *Developer's Studio* icon on the NEMS-F8 terminal server desktop.
         -- from the FILE, OPEN menu, set file type to *.dsw, and select the mrmmps.dsw file from the scenario directory (created in step 1.4 above)
    e.   [Need to do only once.] In the workspace window, double-click on the **mrmmps files** listing, and then on the **Source Files** listing.
         -- find the source code filename, right-click on the filename, and select **Properties** from this sub-menu: a pop-up window entitled "Source File Properties" appears
         -- within the pop-up window, modify the path of the source code (in the "Persist as" line) to point to the new location in the source directory
         -- close the pop-up window by clicking on the 'x' in this window
    f.   To recompile updated code and link to other code, go to the BUILD menu, and select "Rebuild All." A message will appear in the lower window that the executable has been created.
    g.   To execute, go the the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
    h.   The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.

Appendix G-A: Example of An mrmparam File

mrmparam:

```
MODELN          'MRM5      '                                         !8
ACTPROB         'OMLMRM5 '                                           !8
SOLNAM          'MRM5SOL '                                           !8
PATHNF          'mrmpath'                                            !7
TITLE           'MRM5 MULTI  REGION  REFINERY                   ' !48
INBASISN        'inbasis5                                       ' !48
OUTBASISN       'outbasis5 '                                        !10
BASISN          'MRM5      '                                        !10
MPSOUTN         'mpsnrm.txt'                                        !10
PACKN           'MRMPACK   '                                        !10
TRACE           'ON '                                               !3
```

The mrmparam file will run the 5-region MRM model; the act problem will be "OMLMRM5;"" the solution name will be "MRM5SOL;" the data files path will be read from the file "mrmpath;" the title of the MRM model will be "MRM5 MULTI REGION REFINERY;" the advanced basis will be read from   inbasis5;" the optimal basis will be stored in the file "outbasis5;" both the advanced and optimal basis will be named "MRM5;" the mps file will be stored in "mpsnrm.txt;" and the packed matrix will be created and called "MRMPACK." The last line toggles the Ketron debugging utility TRACE.

Appendix G-B: Example of A Path File

mrmpath:

```
NAME          PATHDATA
        DATA    Z:PATHNAME
**        TEXT(6)

accunit     n:/default/input/accunit.v1.2.dat
avoids      n:/default/input/avoids.v1.2.dat
cogener     n:/default/input/cogener.v1.6.dat
crdimprt    n:/default/input/crdimprt.v1.3.dat
demand      n:/default/input/demand.v1.2.dat
distblnd    n:/default/input/distblnd.v1.15.dat
distress    n:/default/input/distress.v1.2.dat
domcrude    n:/default/input/domcrude.v1.3.dat
emish       n:/default/input/emish.v1.2.dat
ethanol     n:/default/input/ethanol.v1.3.dat
fixcols     n:/default/input/fixcols.v1.1.dat
fuelmix     n:/default/input/fuelmix.v1.1.dat
gasoblnd    n:/default/input/gasoblnd.v1.11.dat
main        n:/default/input/refmain.v1.4.dat
ngprod      n:/default/input/ngprod.v1.2.dat
nrfplant    n:/default/input/nrfplant.v1.8.dat
prdimprt    n:/default/input/prdimprt.v1.4.dat
recipes     n:/default/input/recipes.v1.5.dat
refproc     n:/default/input/refproc.v1.27.dat
setrows     n:/default/input/setrows.v1.2.dat
splash      n:/default/input/splash.v1.6.dat
stream      n:/default/input/stream.v1.5.dat
transit     n:/default/input/transit.v1.16.dat
utility     n:/default/input/utility.v1.2.dat
mchproc     n:/default/input/mchproc.v1.12.dat
limpol      n:/default/input/limpol.v1.2.dat
unfinished  n:/default/input/unfinish.v1.5.dat
prdexp      n:/default/input/prdexp.v1.2.dat
akaexp      n:/default/input/akaexp.v1.1.datforeign1
foreign2
fsu
intsetup
epsetup
bldhead
bldstub
ENDATA
```

Appendix G-C: Makefile
(not part of the Developer's Studio Methodology)


```
FLAGS= -c -g -C -qcharlen=16384 -qmaxmem=-1 -qnoprint \
      -qflttrap=zerodivide -qsave
INC= -I/refine/pmm_lp_gen/includes/ -I/default/includes
LIBS= -lwhiz -ldb -lutil -L/usr/lpp/MPS/oml/lib
DIR= /default/objects/
SIR= /default/source/
LIR= /default/objects/
OMLSPA = /refine/pmm_lp_gen/includes/omlspace \
      /refine/pmm_lp_gen/includes/ipmmtest
OBJS= $(LIR)mrm.v1.2.o \
      $(LIR)extpnt.v1.2.o \
      $(LIR)epadjust.v1.2.o \
      $(LIR)bldhead.v1.2.o \
      $(LIR)bldstub.v1.2.o \
      $(LIR)intsetup.v1.2.o \
      $(LIR)foreign.v1.2.o \
      $(LIR)fsu.v1.2.o \
      $(LIR)akaexp.v1.2.o \
      $(LIR)prdexp.v1.4.o \
      $(LIR)unfinished.v1.2.o \
      $(LIR)lplookup.v1.2.o \
      $(LIR)output.v1.2.o \
      $(LIR)ermcrude.v1.2.o \
      $(LIR)ermother.v1.2.o \
      $(LIR)ermprod.v1.2.o \
      $(LIR)tabread.v1.2.o \
      $(LIR)limpol.v1.2.o \
      $(LIR)mchproc.v1.4.o \
      $(LIR)crdimprt.v1.2.o \
      $(LIR)accunit.v1.6.o \
      $(LIR)refproc.v1.6.o \
      $(LIR)nrfplant.v1.5.o \
      $(LIR)stream.v1.2.o \
      $(LIR)distblnd.v1.3.o \
      $(LIR)gasoblnd.v1.4.o \
      $(LIR)domcrude.v1.3.o \
      $(LIR)demand.v1.3.o \
      $(LIR)utility.v1.3.o \
      $(LIR)utilitye.v1.2.o \
      $(LIR)cogener.v1.4.o \
      $(LIR)fuelmix.v1.2.o \
      $(LIR)recipes.v1.2.o \
      $(LIR)ethanol.v1.9.o \
      $(LIR)ngprod.v1.2.o \
      $(LIR)setrows.v1.2.o \
      $(LIR)fixcols.v1.2.o \
      $(LIR)transit3.v1.4.o \
      $(LIR)transit5.v1.2.o \
      $(LIR)prdimprt.v1.2.o \
      $(LIR)splash.v1.3.o \
      $(LIR)distress.v1.2.o \
      $(LIR)avoids.v1.2.o \
      $(DIR)omlanal.v1.6.o \
      $(LIR)emish.v1.2.o \

mrm: $(OBJS)
      xlf -o mrm -g -C $(OBJS) $(LIBS) -bloadmap:loadmap
```

```
$(LIR)mrm.v1.3.o: $(SIR)mrm.f $(OMLSPA)
    xlf $(FLAGS) -o $(LIR)mrm.v1.3.o $(INC) $(SIR)mrm.f
$(LIR)extpnt.v1.2.o: $(SIR)extpnt.f
    xlf $(FLAGS) -o $(LIR)extpnt.v1.2.o $(INC) $(SIR)extpnt.f
$(LIR)epadjust.v1.2.o: $(SIR)epadjust.f
    xlf $(FLAGS) -o $(LIR)epadjust.v1.2.o $(INC) $(SIR)epadjust.f
$(LIR)bldhead.v1.2.o: $(SIR)bldhead.f
    xlf $(FLAGS) -o $(LIR)bldhead.v1.2.o $(INC) $(SIR)bldhead.f
$(LIR)bldstub.v1.2.o: $(SIR)bldstub.f
    xlf $(FLAGS) -o $(LIR)bldstub.v1.2.o $(INC) $(SIR)bldstub.f
$(LIR)intsetup.v1.2.o: $(SIR)intsetup.f
    xlf $(FLAGS) -o $(LIR)intsetup.v1.2.o $(INC) $(SIR)intsetup.f
$(LIR)foreign.v1.2.o: $(SIR)foreign.f
    xlf $(FLAGS) -o $(LIR)foreign.v1.2.o $(INC) $(SIR)foreign.f
$(LIR)fsu.v1.2.o: $(SIR)fsu.f
    xlf $(FLAGS) -o $(LIR)fsu.v1.2.o $(INC) $(SIR)fsu.f
$(LIR)akaexp.v1.2.o: $(SIR)akaexp.f
    xlf $(FLAGS) -o $(LIR)akaexp.v1.2.o $(INC) $(SIR)akaexp.f
$(LIR)prdexp.v1.4.o: $(SIR)prdexp.f
    xlf $(FLAGS) -o $(LIR)prdexp.v1.4.o $(INC) $(SIR)prdexp.f
$(LIR)unfinished.v1.2.o: $(SIR)unfinished.f
    xlf $(FLAGS) -o $(LIR)unfinished.v1.2.o $(INC) $(SIR)unfinished.f
$(LIR)lplookup.v1.2.o: $(SIR)lplookup.f
    xlf $(FLAGS) -o $(LIR)lplookup.v1.2.o $(INC) $(SIR)lplookup.f
$(LIR)output.v1.2.o: $(SIR)output.f
    xlf $(FLAGS) -o $(LIR)output.v1.2.o $(INC) $(SIR)output.f
$(LIR)limpol.v1.2.o: $(SIR)limpol.f
    xlf $(FLAGS) -o $(LIR)limpol.v1.2.o $(INC) $(SIR)limpol.f
$(LIR)tabread.v1.2.o: $(SIR)tabread.f
    xlf $(FLAGS) -o $(LIR)tabread.v1.2.o $(INC) $(SIR)tabread.f
$(LIR)mchproc.v1.4.o: $(SIR)mchproc.f
    xlf $(FLAGS) -o $(LIR)mchproc.v1.4.o $(INC) $(SIR)mchproc.f
$(LIR)ermcrude.v1.2.o: $(SIR)ermcrude.f
    xlf $(FLAGS) -o $(LIR)ermcrude.v1.2.o $(INC) $(SIR)ermcrude.f
$(LIR)ermother.v1.2.o: $(SIR)ermother.f
    xlf $(FLAGS) -o $(LIR)ermother.v1.2.o $(INC) $(SIR)ermother.f
$(LIR)ermprod.v1.2.o: $(SIR)ermprod.f
    xlf $(FLAGS) -o $(LIR)ermprod.v1.2.o $(INC) $(SIR)ermprod.f
$(LIR)crdimprt.v1.2.o: $(SIR)crdimprt.f
    xlf $(FLAGS) -o $(LIR)crdimprt.v1.2.o $(INC) $(SIR)crdimprt.f
$(LIR)accunit.v1.6.o: $(SIR)accunit.f
    xlf $(FLAGS) -o $(LIR)accunit.v1.6.o $(INC) $(SIR)accunit.f
$(LIR)refproc.v1.6.o: $(SIR)refproc.f
    xlf $(FLAGS) -o $(LIR)refproc.v1.6.o $(INC) $(SIR)refproc.f
$(LIR)nrfplant.v1.5.o: $(SIR)nrfplant.f
    xlf $(FLAGS) -o $(LIR)nrfplant.v1.5.o $(INC) $(SIR)nrfplant.f
$(LIR)stream.v1.2.o: $(SIR)stream.f
    xlf $(FLAGS) -o $(LIR)stream.v1.2.o $(INC) $(SIR)stream.f
$(LIR)distblnd.v1.3.o: $(SIR)distblnd.f
    xlf $(FLAGS) -o $(LIR)distblnd.v1.3.o $(INC) $(SIR)distblnd.f
$(LIR)gasoblnd.v1.4.o: $(SIR)gasoblnd.f
    xlf $(FLAGS) -o $(LIR)gasoblnd.v1.4.o $(INC) $(SIR)gasoblnd.f
$(LIR)domcrude.v1.3.o: $(SIR)domcrude.f
    xlf $(FLAGS) -o $(LIR)domcrude.v1.3.o $(INC) $(SIR)domcrude.f
$(LIR)demand.v1.3.o: $(SIR)demand.f
    xlf $(FLAGS) -o $(LIR)demand.v1.3.o $(INC) $(SIR)demand.f
$(LIR)utility.v1.3.o: $(SIR)utility.f
    xlf $(FLAGS) -o $(LIR)utility.v1.3.o $(INC) $(SIR)utility.f
$(LIR)utilitye.v1.2.o: $(SIR)utilitye.f
    xlf $(FLAGS) -o $(LIR)utilitye.v1.2.o $(INC) $(SIR)utilitye.f
$(LIR)cogener.v1.4.o: $(SIR)cogener.f
    xlf $(FLAGS) -o $(LIR)cogener.v1.4.o $(INC) $(SIR)cogener.f
$(LIR)fuelmix.v1.2.o: $(SIR)fuelmix.f
```

```
        xlf $(FLAGS) -o $(LIR)fuelmix.v1.2.o $(INC) $(SIR)fuelmix.f
$(LIR)recipes.v1.2.o: $(SIR)recipes.f
        xlf $(FLAGS) -o $(LIR)recipes.v1.2.o $(INC) $(SIR)recipes.f
$(LIR)ethanol.v1.9.o: $(SIR)ethanol.f
        xlf $(FLAGS) -o $(LIR)ethanol.v1.9.o $(INC) $(SIR)ethanol.f
$(LIR)ngprod.v1.2.o: $(SIR)ngprod.f
        xlf $(FLAGS) -o $(LIR)ngprod.v1.2.o $(INC) $(SIR)ngprod.f
$(LIR)setrows.v1.2.o: $(SIR)setrows.f
        xlf $(FLAGS) -o $(LIR)setrows.v1.2.o $(INC) $(SIR)setrows.f
$(LIR)fixcols.v1.2.o: $(SIR)fixcols.f
        xlf $(FLAGS) -o $(LIR)fixcols.v1.2.o $(INC) $(SIR)fixcols.f
$(LIR)transit3.v1.4.o: $(SIR)transit3.f
        xlf $(FLAGS) -o $(LIR)transit3.v1.4.o $(INC) $(SIR)transit3.f
$(LIR)transit5.v1.2.o: $(SIR)transit5.f
        xlf $(FLAGS) -o $(LIR)transit5.v1.2.o $(INC) $(SIR)transit5.f
$(LIR)prdimprt.v1.2.o: $(SIR)prdimprt.f
        xlf $(FLAGS) -o $(LIR)prdimprt.v1.2.o $(INC) $(SIR)prdimprt.f
$(LIR)splash.v1.3.o: $(SIR)splash.f
        xlf $(FLAGS) -o $(LIR)splash.v1.3.o $(INC) $(SIR)splash.f
$(LIR)distress.v1.2.o: $(SIR)distress.f
        xlf $(FLAGS) -o $(LIR)distress.v1.2.o $(INC) $(SIR)distress.f
$(LIR)avoids.v1.2.o: $(SIR)avoids.f
        xlf $(FLAGS) -o $(LIR)avoids.v1.2.o $(INC) $(SIR)avoids.f
$(LIR)emish.v1.2.o  : $(SIR)emish.f
        xlf $(FLAGS) -o $(LIR)emish.v1.2.o $(INC) $(SIR)emish.f
```

Appendix G-D: Common Blocks

File: ipmmtest

```
! $Header: N:/default/includes/RCS/ipmmtest,v 1.3 1999/12/21 14:13:29 DSA Exp $
      COMMON /IPMMREAL/MAX, MIN, VALUE, INFINITY,             &
            WOP,                                   &
            REALURYR, YRDOLLAR, ENV, LOC, OVCOST
      REAL*8        MAX(1000)
      REAL*8        MIN(1000)
      REAL*8        VALUE(1000)
      REAL*8        INFINITY
      REAL*8        WOP(26)
      REAL*8        REALURYR
      REAL*8        YRDOLLAR
      REAL*8        ENV(5)
      REAL*8        LOC(5)
      REAL*8        OVCOST(5)
      COMMON /IPMMINT/COUNT, DUMMY,                      &
            I, IRET, IROWS, J, JCOLS, K, KROWS, NUMREG,EXPREGSS,    &
            USERYEAR, DMDREG, NUMYRS, DBPROBG, COMTAB1, COMTAB2
      INTEGER*4     COUNT
      INTEGER*4     DUMMY
      INTEGER*4     I
      INTEGER*4     IRET
      INTEGER*4     IROWS
      INTEGER*4     J
      INTEGER*4     JCOLS
      INTEGER*4     K
      INTEGER*4     KROWS
      INTEGER*4     NUMREG
      INTEGER*4     EXPREGSS
      INTEGER*4     USERYEAR
      INTEGER*4     DMDREG
      INTEGER*4     NUMYRS
      INTEGER*4     DBPROBG(22)
      INTEGER*4     COMTAB1(13)
      INTEGER*4     COMTAB2(13)
      COMMON /IPMMCHAR/HEAD, STUB, PROCESS, BND, CNAME,         &
         DECKNAME, LRNAME, OBJ, RHS, RNAME, RCHAR5, REGION,       &
         EXPREG, DEMNDREG, DEMNDPAD, PATH, FRCRD, EXPRD
      CHARACTER*8              HEAD(1000)
      CHARACTER*8              STUB(1000)
      CHARACTER*8              PROCESS(1000)
      CHARACTER*8              BND
      CHARACTER*8              CNAME
      CHARACTER*8              DECKNAME
      CHARACTER*8              LRNAME
      CHARACTER*8              OBJ
      CHARACTER*8              RHS
      CHARACTER*8              RNAME
      CHARACTER*5              RCHAR5
      CHARACTER*1              REGION(5)
      CHARACTER*2              EXPREG(5)
      CHARACTER*1              DEMNDREG(9)
      CHARACTER*1              DEMNDPAD(9)
      CHARACTER*48             PATH(40)
      CHARACTER*8              FRCRD(5)
      CHARACTER*8              EXPRD(11)
```

File: lpout

Common block used for report writing

```
C  LPOUT COMMON BLOCK FOR USE IN OML MATRIX SOLUTION
                              !
    REAL       PRDPRC(9,18)
    REAL       BASECAP(5,27)
    REAL       BASEUTL(5,27)
    REAL       INVCAP(5,27)
    REAL       INVUTL(5,27)
    REAL       TOTCAP(5,27)
    REAL       TOTUTL(5,27)
    REAL       TOTSUP(6)
    REAL       PUTL(5,27)
    REAL       RFCRDCR(6)
    REAL       RFCRDAKA(6)
    REAL       RFCRDL48(6)
    REAL       RFQICRD(6)
    REAL       RFIMCR(6)
    REAL       RFQISPR(6)
    REAL       RFIMTP(6)
    REAL       RFQEXCRD(6)
    REAL       RFPQNGL(6)
    REAL       RFQNGLRF(6)
    REAL       NGLRF(6)
    REAL       NGLMK(6)
    REAL       RFQPRCG(6)
    REAL       RFPQIPRDT(6)
    REAL       RFPQUFC(6)
    REAL       RFQEXPRDT(6)
    REAL       RFQPRDDM(11)
    REAL       QCDUPD(6)
    REAL       RFQDINPOT(6)
    REAL       RFETHD(6)
    REAL       RFMTBI(6)
    REAL       RFMETI(6)
    REAL       RFMETD(6)
    REAL       RFMETCHM(6)
    REAL       RFMETM85(6)
    REAL       RFMETETH(6)
    REAL       RFETHE85(6)
    REAL       RFETHETB(6)
    REAL       RFETHMGS(6)
    REAL       RFCRDOTH(6)
    REAL       OTHOXY(6)
    REAL       QPRDIMD(11,23)
    REAL       QPRDEXD(6,23)
    COMMON/LPTAB/PRDPRC,BASECAP,BASEUTL,INVCAP,INVUTL,TOTCAP,           &
    TOTUTL,PUTL,RFCRDDCR,RFCrtAKA,RFCrtL48,RFQICRD,RFIMCR,            &
    RFQEXCRD,RFPQNGL,RFQNGLRF,NGLRF,NGLMK,RFQPRCG,RFPQIPRDT,          &
    RFPQUFC,RFQEXPRDT,RFQPRDDM,QCDUPD,RFQDINPOT,RFETHD,RFMTBI,        &
    RFMETI,RFMETD,RFMETCHM,RFMETM85,RFMETETH,RFETHE85,TOTSUP,          &
    RFQISPR,RFIMTP,RFETHETB,RFETHMGS,OTHOXY,QPRDIMD,QPRDEXD,          &
    RFCRDOTH
```

File: DFINC2

Common block used for OML database functions

```
! $Header: N:/default/includes/RCS/dfinc2,v 1.5 2000/05/18 15:12:11 DSA Exp $
    INTERFACE
    INTEGER*4 FUNCTION DFINIT  (TITLE,TBUF,LEN)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFINIT
    !DEC$ATTRIBUTES REFERENCE :: TITLE,TBUF,LEN
    CHARACTER*8 TITLE
    CHARACTER*1 TBUF(2)
    INTEGER*4 LEN
    END FUNCTION

    INTEGER*4 FUNCTION SetConsolePrintMode(IVAL)
    !DEC$ATTRIBUTES STDCALL, ALIAS: '_SetConsolePrintMode@4' :: SetConsolePrintMode
    !DEC$ATTRIBUTES VALUE :: IVAL
    INTEGER*4 IVAL
    END FUNCTION

    INTEGER*4 FUNCTION DFOPEN  (DBFILE,ACTFILE)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFOPEN
    !DEC$ATTRIBUTES REFERENCE :: DBFILE,ACTFILE
    INTEGER*4 DBFILE(2)
    CHARACTER*8 ACTFILE
    END FUNCTION

    INTEGER*4 FUNCTION DFCLOSE (DBFILE)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFCLOSE
    !DEC$ATTRIBUTES REFERENCE :: DBFILE
    INTEGER*4 DBFILE(2)
    END FUNCTION

    INTEGER*4 FUNCTION DFDEL   (DBFILE)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFDEL
    !DEC$ATTRIBUTES REFERENCE :: DBFILE
    INTEGER*4 DBFILE(2)
    END FUNCTION

    INTEGER*4 FUNCTION DFLIST  (DBFILE,MASK,PNAME)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFLIST
    !DEC$ATTRIBUTES REFERENCE :: DBFILE,MASK,PNAME
    INTEGER*4 DBFILE(2)
    CHARACTER*8 MASK
    CHARACTER*8 PNAME
    END FUNCTION

    INTEGER*4 FUNCTION DFPINIT (DB,DBFILE,ACTPROB)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPINIT
    !DEC$ATTRIBUTES REFERENCE :: DB,DBFILE,ACTPROB
    INTEGER*4 DB(2)
    INTEGER*4 DBFILE(2)
    CHARACTER*8 ACTPROB
    END FUNCTION

    INTEGER*4 FUNCTION DFPDEL  (DB)
    !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPDEL
    !DEC$ATTRIBUTES REFERENCE :: DB
    INTEGER*4 DB(2)
    END FUNCTION

    INTEGER*4 FUNCTION DFPCPY  (TO,FROM)
```

```
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPCPY
!DEC$ATTRIBUTES REFERENCE :: TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END FUNCTION


INTEGER*4 FUNCTION DFPLIST (DB,MASK,TNAME,TYPE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPLIST
!DEC$ATTRIBUTES REFERENCE :: DB,MASK,TNAME,TYPE
INTEGER*4 DB(2)
CHARACTER*8 MASK
CHARACTER*8 TNAME
INTEGER*4 TYPE
END FUNCTION


INTEGER*4 FUNCTION DFPTDEL (DB)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPTDEL
!DEC$ATTRIBUTES REFERENCE :: DB
INTEGER*4 DB(2)
END FUNCTION


INTEGER*4 FUNCTION DFPTCPY (TO,FROM)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPTCPY
!DEC$ATTRIBUTES REFERENCE :: TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END FUNCTION


INTEGER*4 FUNCTION DFPMDEL (DB)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPMDEL
!DEC$ATTRIBUTES REFERENCE :: DB
INTEGER*4 DB(2)
END FUNCTION


INTEGER*4 FUNCTION DFPMCPY (TO,FROM)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPMCPY
!DEC$ATTRIBUTES REFERENCE :: TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END FUNCTION


INTEGER*4 FUNCTION DFPSDEL (DB)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPSDEL
!DEC$ATTRIBUTES REFERENCE :: DB
INTEGER*4 DB(2)
END FUNCTION


INTEGER*4 FUNCTION DFPSCPY (TO,FROM)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPSCPY
!DEC$ATTRIBUTES REFERENCE :: TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END FUNCTION


INTEGER*4 FUNCTION DFPRTBI (DB,FILENAME,DECKNAME,PRNTSW,TABLIST)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFPRTBI
!DEC$ATTRIBUTES REFERENCE :: DB,FILENAME,DECKNAME,PRNTSW,TABLIST
INTEGER*4 DB(2)
CHARACTER*8 FILENAME
CHARACTER*8 DECKNAME
INTEGER*4 PRNTSW
CHARACTER*8 TABLIST
END FUNCTION
```

```
INTEGER*4 FUNCTION DFTINIT (TABLE,DB,TABNAME,TYPE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTINIT
!DEC$ATTRIBUTES REFERENCE ::  TABLE,DB,TABNAME,TYPE
INTEGER*4 TABLE(2)
INTEGER*4 DB(2)
CHARACTER*8 TABNAME
INTEGER*4 TYPE
END FUNCTION


INTEGER*4 FUNCTION DFTNEW  (TABLE,DB,TABNAME,TYPE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTNEW
!DEC$ATTRIBUTES REFERENCE ::  TABLE,DB,TABNAME,TYPE
INTEGER*4 TABLE(2)
INTEGER*4 DB(2)
CHARACTER*8 TABNAME
INTEGER*4 TYPE
END FUNCTION


INTEGER*4 FUNCTION DFTDIM  (TABLE,NROWS,NCOLS)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTDIM
!DEC$ATTRIBUTES REFERENCE ::  TABLE,NROWS,NCOLS
INTEGER*4 TABLE(2)
INTEGER*4 NROWS
INTEGER*4 NCOLS
END FUNCTION


INTEGER*4 FUNCTION DFTDEL  (TABLE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTDEL
!DEC$ATTRIBUTES REFERENCE ::  TABLE
INTEGER*4 TABLE(2)
END FUNCTION


INTEGER*4 FUNCTION DFTCPY  (TO,FROM)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTCPY
!DEC$ATTRIBUTES REFERENCE ::  TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END FUNCTION


INTEGER*4 FUNCTION DFTSNDX (TABLE,STUB)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTSNDX
!DEC$ATTRIBUTES REFERENCE ::  TABLE,STUB
INTEGER*4 TABLE(2)
CHARACTER*8 STUB
END FUNCTION


INTEGER*4 FUNCTION DFTHNDX (TABLE,HEAD)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTHNDX
!DEC$ATTRIBUTES REFERENCE ::  TABLE,HEAD
INTEGER*4 TABLE(2)
CHARACTER*8 HEAD
END FUNCTION


INTEGER*4 FUNCTION DFTSMSK (TABLE,START,MASK)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTSMSK
!DEC$ATTRIBUTES REFERENCE ::  TABLE,START,MASK
INTEGER*4 TABLE(2)
INTEGER*4 START
CHARACTER*8 MASK
END FUNCTION


INTEGER*4 FUNCTION DFTHMSK (TABLE,START,MASK)
```

```
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFTHMSK
!DEC$ATTRIBUTES REFERENCE :: TABLE,START,MASK
INTEGER*4 TABLE(2)
INTEGER*4 START
CHARACTER*8 MASK
END FUNCTION


INTEGER*4 FUNCTION DFTNDX (TABLE,RNAME,CNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFTNDX
!DEC$ATTRIBUTES REFERENCE :: TABLE,RNAME,CNAME,VALUE
INTEGER*4 TABLE(2)
INTEGER*4 RNAME
INTEGER*4 CNAME
INTEGER*4 VALUE(1)
END FUNCTION


INTEGER*4 FUNCTION DFTGETVC (TABLE,RNAME,CNAME,VALUE,COUNT)
!DEC$ATTRIBUTES STDCALL,REFERENCE,ALIAS: '_dftget@20' :: DFTGETVC
!DEC$ATTRIBUTES REFERENCE :: TABLE,RNAME,CNAME,VALUE,COUNT
INTEGER*4 TABLE(2)
INTEGER*4 RNAME
CHARACTER*8 CNAME(1)
REAL*8   VALUE(1)
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION DFTGETV (TABLE,RNAME,CNAME,VALUE,COUNT)
!DEC$ATTRIBUTES STDCALL,REFERENCE,ALIAS: '_dftget@20' :: DFTGETV
!DEC$ATTRIBUTES REFERENCE :: TABLE,RNAME,CNAME,VALUE,COUNT
INTEGER*4 TABLE(2)
INTEGER*4 RNAME
INTEGER*4 CNAME
REAL*8   VALUE(1)
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION DFTGETN (TABLE,RNAME,CNAME,VALUE,COUNT)
!DEC$ATTRIBUTES STDCALL,REFERENCE,ALIAS: '_dftget@20' :: DFTGETN
!DEC$ATTRIBUTES REFERENCE :: TABLE,RNAME,CNAME,VALUE,COUNT
INTEGER*4 TABLE(2)
INTEGER*4 RNAME
INTEGER*4 CNAME
CHARACTER*8 VALUE(1)
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION DFTPUT (TABLE,RNAME,CNAME,VALUE,COUNT)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFTPUT
!DEC$ATTRIBUTES REFERENCE :: TABLE,RNAME,CNAME,VALUE,COUNT
INTEGER*4 TABLE(2)
INTEGER*4 RNAME
INTEGER*4 CNAME
INTEGER*4 VALUE
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION DFTSADD (TABLE,INDEX,STUB)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFTSADD
!DEC$ATTRIBUTES REFERENCE :: TABLE,INDEX,STUB
INTEGER*4 TABLE(2)
INTEGER*4 INDEX
CHARACTER*8 STUB
END FUNCTION
```

```
INTEGER*4 FUNCTION DFTHADD (TABLE,INDEX,HEAD)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTHADD
!DEC$ATTRIBUTES REFERENCE ::  TABLE,INDEX,HEAD
INTEGER*4 TABLE(2)
INTEGER*4 INDEX
CHARACTER*8 HEAD
END FUNCTION

INTEGER*4 FUNCTION DFTSDEL (TABLE,STUB)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTSDEL
!DEC$ATTRIBUTES REFERENCE ::  TABLE,STUB
INTEGER*4 TABLE(2)
INTEGER*4 STUB
END FUNCTION

INTEGER*4 FUNCTION DFTHDEL (TABLE,HEAD)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTHDEL
!DEC$ATTRIBUTES REFERENCE ::  TABLE,HEAD
INTEGER*4 TABLE(2)
INTEGER*4 HEAD
END FUNCTION

INTEGER*4 FUNCTION DFTDISP (TABLE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFTDISP
!DEC$ATTRIBUTES REFERENCE ::  TABLE
INTEGER*4 TABLE(2)
END FUNCTION

INTEGER*4 FUNCTION DFMINIT (DB,MODE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMINIT
!DEC$ATTRIBUTES REFERENCE ::  DB,MODE
INTEGER*4 DB(2)
INTEGER*4 MODE
END FUNCTION

INTEGER*4 FUNCTION DFMEND  ()
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMEND
END FUNCTION

INTEGER*4 FUNCTION DFMSTAT (STAT)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMSTAT
!DEC$ATTRIBUTES REFERENCE ::  STAT
INTEGER*4 STAT(9)
END FUNCTION

INTEGER*4 FUNCTION DFMCRTP (RNAME,TYPE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMCRTP
!DEC$ATTRIBUTES REFERENCE ::  RNAME,TYPE
CHARACTER*8 RNAME
CHARACTER*8 TYPE
END FUNCTION

INTEGER*4 FUNCTION DFMCRSC (RNAME,SCALE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMCRSC
!DEC$ATTRIBUTES REFERENCE ::  RNAME,SCALE
CHARACTER*8 RNAME
REAL*8 SCALE
END FUNCTION

INTEGER*4 FUNCTION DFMCCSC (CNAME,SCALE)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMCCSC
!DEC$ATTRIBUTES REFERENCE ::  CNAME,SCALE
```

```
CHARACTER*8 CNAME
REAL*8 SCALE
END FUNCTION


INTEGER*4 FUNCTION DFMCVAL (CNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMCVAL
!DEC$ATTRIBUTES REFERENCE :: CNAME,RNAME,VALUE
CHARACTER*8 CNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMMVAL (CNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMMVAL
!DEC$ATTRIBUTES REFERENCE :: CNAME,RNAME,VALUE
CHARACTER*8 CNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMCCLR (CNAME,FLAG)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMCCLR
!DEC$ATTRIBUTES REFERENCE :: CNAME,FLAG
CHARACTER*8 CNAME
INTEGER*4 FLAG
END FUNCTION


INTEGER*4 FUNCTION DFMCRHS (CNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMCRHS
!DEC$ATTRIBUTES REFERENCE :: CNAME,RNAME,VALUE
CHARACTER*8 CNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMCRNG (RNGNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMCRNG
!DEC$ATTRIBUTES REFERENCE :: RNGNAME,RNAME,VALUE
CHARACTER*8 RNGNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMCBND (BNDNAME,CNAME,LVALUE,UVALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMCBND
!DEC$ATTRIBUTES REFERENCE :: BNDNAME,CNAME,LVALUE,UVALUE
CHARACTER*8 BNDNAME
CHARACTER*8 CNAME
REAL*8 LVALUE
REAL*8 UVALUE
END FUNCTION


INTEGER*4 FUNCTION DFMRRTP (RNAME,TYPE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRRTP
!DEC$ATTRIBUTES REFERENCE :: RNAME,TYPE
CHARACTER*8 RNAME
CHARACTER*8 TYPE
END FUNCTION


INTEGER*4 FUNCTION DFMRRSC (RNAME,SCALE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRRSC
!DEC$ATTRIBUTES REFERENCE :: RNAME,SCALE
CHARACTER*8 RNAME
```

```
REAL*8 SCALE
END FUNCTION


INTEGER*4 FUNCTION DFMRCSC (CNAME,SCALE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRCSC
!DEC$ATTRIBUTES REFERENCE :: CNAME,SCALE
CHARACTER*8 CNAME
REAL*8 SCALE
END FUNCTION


INTEGER*4 FUNCTION DFMRVAL (CNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRVAL
!DEC$ATTRIBUTES REFERENCE :: CNAME,RNAME,VALUE
CHARACTER*8 CNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMRRHS (CNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRRHS
!DEC$ATTRIBUTES REFERENCE :: CNAME,RNAME,VALUE
CHARACTER*8 CNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMRRNG (RNGNAME,RNAME,VALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRRNG
!DEC$ATTRIBUTES REFERENCE :: RNGNAME,RNAME,VALUE
CHARACTER*8 RNGNAME
CHARACTER*8 RNAME
REAL*8 VALUE
END FUNCTION


INTEGER*4 FUNCTION DFMRBND (BNDNAME,CNAME,LVALUE,UVALUE)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMRBND
!DEC$ATTRIBUTES REFERENCE :: BNDNAME,CNAME,LVALUE,UVALUE
CHARACTER*8 BNDNAME
CHARACTER*8 CNAME
REAL*8 LVALUE
REAL*8 UVALUE
END FUNCTION

INTEGER*4 FUNCTION DFMIROW (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMIROW
!DEC$ATTRIBUTES REFERENCE :: NAME
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION DFMICOL (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMICOL
!DEC$ATTRIBUTES REFERENCE :: NAME
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION DFMIRHS (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMIRHS
!DEC$ATTRIBUTES REFERENCE :: NAME
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION DFMIRNG (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMIRNG
```

```
          !DEC$ATTRIBUTES REFERENCE ::  NAME
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMIBND (NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMIBND
          !DEC$ATTRIBUTES REFERENCE ::  NAME
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMNROW (INDEX,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMNROW
          !DEC$ATTRIBUTES REFERENCE ::  INDEX,NAME
          INTEGER*4 INDEX
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMNCOL (INDEX,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMNCOL
          !DEC$ATTRIBUTES REFERENCE ::  INDEX,NAME
          INTEGER*4 INDEX
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMNRHS (INDEX,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMNRHS
          !DEC$ATTRIBUTES REFERENCE ::  INDEX,NAME
          INTEGER*4 INDEX
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMNRNG (INDEX,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMNRNG
          !DEC$ATTRIBUTES REFERENCE ::  INDEX,NAME
          INTEGER*4 INDEX
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMNBND (INDEX,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMNBND
          !DEC$ATTRIBUTES REFERENCE ::  INDEX,NAME
          INTEGER*4 INDEX
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMLROW (MASK,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMLROW
          !DEC$ATTRIBUTES REFERENCE ::  MASK,NAME
          CHARACTER*8 MASK
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMLCOL (MASK,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMLCOL
          !DEC$ATTRIBUTES REFERENCE ::  MASK,NAME
          CHARACTER*8 MASK
          CHARACTER*8 NAME
          END FUNCTION

          INTEGER*4 FUNCTION DFMLRHS (MASK,NAME)
          !DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFMLRHS
          !DEC$ATTRIBUTES REFERENCE ::  MASK,NAME
          CHARACTER*8 MASK
```

```
         CHARACTER*8 NAME
         END FUNCTION


         INTEGER*4 FUNCTION DFMLRNG (MASK,NAME)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMLRNG
         !DEC$ATTRIBUTES REFERENCE :: MASK,NAME
         CHARACTER*8 MASK
         CHARACTER*8 NAME
         END FUNCTION


         INTEGER*4 FUNCTION DFMLBND (MASK,NAME)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMLBND
         !DEC$ATTRIBUTES REFERENCE :: MASK,NAME
         CHARACTER*8 MASK
         CHARACTER*8 NAME
         END FUNCTION


         INTEGER*4 FUNCTION DFMLVAL (CNAME,START,INDEX,VALUE,COUNT)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMLVAL
         !DEC$ATTRIBUTES REFERENCE :: CNAME,START,INDEX,VALUE,COUNT
         CHARACTER*8 CNAME
         INTEGER*4 START
         INTEGER*4 INDEX(*)
         REAL*8 VALUE(*)
         INTEGER*4 COUNT
         END FUNCTION


         INTEGER*4 FUNCTION DFMTAB  (TABLE)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFMTAB
         !DEC$ATTRIBUTES REFERENCE :: TABLE
         INTEGER*4 TABLE
         END FUNCTION


         INTEGER*4 FUNCTION DFSINIT (DB,CNAME)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFSINIT
         !DEC$ATTRIBUTES REFERENCE :: DB,CNAME
         INTEGER*4 DB(2)
         CHARACTER*8 CNAME
         END FUNCTION


         INTEGER*4 FUNCTION DFSROW  (NAME,SELECT,STAT,VALUE)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFSROW
         !DEC$ATTRIBUTES REFERENCE :: NAME,SELECT,STAT,VALUE
         CHARACTER*8 NAME
         CHARACTER*8 SELECT
         character*2 stat
         REAL*8 VALUE(5)
         END FUNCTION


         INTEGER*4 FUNCTION DFSCOL  (NAME,SELECT,STAT,VALUE)
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFSCOL
         !DEC$ATTRIBUTES REFERENCE :: NAME,SELECT,STAT,VALUE
         CHARACTER*8 NAME
         CHARACTER*8 SELECT
         character*2 STAT
         REAL*8 VALUE(5)
         END FUNCTION


         INTEGER*4 FUNCTION DFSEND  ()
         !DEC$ATTRIBUTES STDCALL,REFERENCE :: DFSEND
         END FUNCTION


         SUBROUTINE DFNCPY  (TO,FROM)
```

```
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNCPY
!DEC$ATTRIBUTES REFERENCE ::  TO,FROM
INTEGER*4 TO
INTEGER*4 FROM
END SUBROUTINE

SUBROUTINE DFNCAT  (NAME1,NAME2)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNCAT
!DEC$ATTRIBUTES REFERENCE ::  NAME1,NAME2
CHARACTER*8 NAME1
CHARACTER*8 NAME2
END SUBROUTINE

SUBROUTINE DFNFILL (NAME1,NAME2)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNFILL
!DEC$ATTRIBUTES REFERENCE ::  NAME1,NAME2
CHARACTER*8 NAME1
CHARACTER*8 NAME2
END SUBROUTINE

SUBROUTINE DFNINCR (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNINCR
!DEC$ATTRIBUTES REFERENCE ::  NAME
CHARACTER*8 NAME
END SUBROUTINE

SUBROUTINE DFNMASK (NAME1,NAME2)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNMASK
!DEC$ATTRIBUTES REFERENCE ::  NAME1,NAME2
CHARACTER*8 NAME1
CHARACTER*8 NAME2
END SUBROUTINE

SUBROUTINE DFNSQOZ (NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNSQOZ
!DEC$ATTRIBUTES REFERENCE ::  NAME
CHARACTER*8 NAME
END SUBROUTINE

SUBROUTINE DFNSHFT (NAME,N)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNSHFT
!DEC$ATTRIBUTES REFERENCE ::  NAME,N
CHARACTER*8 NAME
INTEGER*4 N
END SUBROUTINE

INTEGER*4 FUNCTION DFNCMP  (NAME1,NAME2)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNCMP
!DEC$ATTRIBUTES REFERENCE ::  NAME1,NAME2
CHARACTER*8 NAME1
CHARACTER*8 NAME2
END FUNCTION

INTEGER*4 FUNCTION DFNMCMP (MASK,NAME)
!DEC$ATTRIBUTES STDCALL,REFERENCE ::  DFNMCMP
!DEC$ATTRIBUTES REFERENCE ::  MASK,NAME
CHARACTER*8 MASK
CHARACTER*8 NAME
END FUNCTION

END INTERFACE
```

File: WFINC2

Common block used for the WHIZ optimizer

```
! $Header: N:/default/includes/RCS/wfinc2,v 1.6 2005/03/25 15:33:47 RSC Exp $
    TYPE CR
    SEQUENCE
!
    CHARACTER*8 XNAME
    INTEGER    XCORE
    INTEGER    XCORELEN
!
    CHARACTER*8 XACTCASE
    CHARACTER*8 XACTFILE
    CHARACTER*8 XACTPROB
    CHARACTER*8 XBOUND
    CHARACTER*8 XCHOBJ
    CHARACTER*8 XCHRHS
    CHARACTER*8 XCMASK
    CHARACTER*8 XDATA
    CHARACTER*8 XINSERT
    CHARACTER*8 XLOADB
    CHARACTER*8 XMINMAX
    CHARACTER*8 XOBJ
    CHARACTER*8 XPUNCH
    CHARACTER*8 XRANGE
    CHARACTER*8 XRHS
    CHARACTER*8 XRMASK
    CHARACTER*8 XRNGFILE
    CHARACTER*8 XRNGPRNT
    CHARACTER*8 XSAVEB
    CHARACTER*8 XSOLFILE
    CHARACTER*8 XSOLPRNT
    CHARACTER*8 XSOLSTAT
    CHARACTER*8 XTABCASE
!
    REAL*8     XEPS
    REAL*8     XFUNCT
    REAL*8     XINTGOAL
    REAL*8     XMAXVAR
    REAL*8     XPARAM
    REAL*8     XPENCOST
    REAL*8     XPHI
    REAL*8     XRSTOP
    REAL*8     XSIF
    REAL*8     XSSCALE
    REAL*8     XTHETA
    REAL*8     XTOLCHK
    REAL*8     XTOLCHZR
    REAL*8     XTOLCKRW
    REAL*8     XTOLCLRT
    REAL*8     XTOLDJ
    REAL*8     XTOLERR
    REAL*8     XTOLFSTM
    REAL*8     XTOLINV
    REAL*8     XTOLLMAX
    REAL*8     XTOLPERT
    REAL*8     XTOLPIV
    REAL*8     XTOLREL
    REAL*8     XTOLRMAX
    REAL*8     XTOLRWRT
```

```
      REAL*8    XTOLUREL
      REAL*8    XTOLV
      REAL*8    XTOLZE
      REAL*8    XZERO
!
      INTEGER   XCHECKSW
      INTEGER   XCLOCKSW
      INTEGER   XCOMPERR
      INTEGER   XCOMPSW
      INTEGER   XCRASHSW
      INTEGER   XCYCLESW
      INTEGER   XDEGEND
      INTEGER   XDEGMAX
      INTEGER   XDEMAND
      INTEGER   XDETAIL
      INTEGER   XDOATTN
      INTEGER   XDODELTM
      INTEGER   XDOFEAS
      INTEGER   XDOFREQ1
      INTEGER   XDONFS
      INTEGER   XDOUNB
      INTEGER   XDUAL
      INTEGER   XEQUIL
      INTEGER   XFEAS
      INTEGER   XFREQINV
      INTEGER   XFREQLOG
      INTEGER   XFREQSAV
      INTEGER   XFREQSUM
      INTEGER   XINVERT
      INTEGER   XITERNO
      INTEGER   XJ
      INTEGER   XLUDENSE
      INTEGER   XLUFILL
      INTEGER   XLUINV
      INTEGER   XM
      INTEGER   XMAJERR
      INTEGER   XMAXITER
      INTEGER   XMAXPASS
      INTEGER   XMAXTIME
      INTEGER   XMINERR
      INTEGER   XNEGDJ
      INTEGER   XNET
      INTEGER   XNIF
      INTEGER   XNOWT
      INTEGER   XRUNMODE
      INTEGER   XRYANOSB
      INTEGER   XSCALESW
      INTEGER   XSCRNSW
      INTEGER   XSLPNZ
      INTEGER   XTIMESAV
      INTEGER   XTRACE
      INTEGER   XTRAN
      INTEGER   XUNIQUES
      INTEGER   XUNBDNDX
      INTEGER   XUSEFREE
      END TYPE CR
!
      INTERFACE
!
       subroutine getwcr ( icrloc )
      !DEC$ATTRIBUTES STDCALL, REFERENCE ::  getwcr
      !DEC$ATTRIBUTES REFERENCE ::  icrloc
       integer*4 icrloc
```

```
   end subroutine

SUBROUTINE DALPHA  (MESSAGE, POS, LENG)
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  DALPHA
!DEC$ATTRIBUTES REFERENCE ::  MESSAGE, POS, LENG
CHARACTER(*) MESSAGE
INTEGER*4 POS
INTEGER*4 LENG
END SUBROUTINE

INTEGER*4 FUNCTION WFINIT  ( TITLE, TBUF, LEN )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFINIT
!DEC$ATTRIBUTES REFERENCE ::  TITLE, TBUF, LEN
CHARACTER*8 TITLE
real*8 TBUF(*)
INTEGER*4 LEN
END FUNCTION

INTEGER*4 FUNCTION WFDEF   ( MODEL, LEN, MODLNAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFDEF
!DEC$ATTRIBUTES REFERENCE ::  MODEL, LEN, MODLNAME
REAL*8 MODEL(*)
INTEGER*4 LEN
CHARACTER*8 MODLNAME
END FUNCTION

INTEGER*4 FUNCTION WFSET   ( MODEL )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFSET
!DEC$ATTRIBUTES REFERENCE ::  MODEL
REAL*8 MODEL(*)
END FUNCTION

INTEGER*4 FUNCTION WFMPSIN ( ACTFILE, ACTPROB, FILENAME,  &
    DECKANME, PRNTSW, REVISE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFMPSIN
!DEC$ATTRIBUTES REFERENCE ::  ACTFILE, ACTPROB, FILENAME
!DEC$ATTRIBUTES REFERENCE ::   DECKANME, PRNTSW, REVISE
CHARACTER*8 ACTFILE
CHARACTER*8 ACTPROB
CHARACTER*8 FILENAME
CHARACTER*8 DECKANME
INTEGER*4 PRNTSW
INTEGER*4 REVISE
END FUNCTION

INTEGER*4 FUNCTION WFMPSOU ( ACTFILE, ACTPROB, FILENAME, &
 DECKANME, ONECOEF )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFMPSOU
!DEC$ATTRIBUTES REFERENCE ::  ACTFILE, ACTPROB, FILENAME
!DEC$ATTRIBUTES REFERENCE ::  DECKANME, ONECOEF
CHARACTER*8 ACTFILE
CHARACTER*8 ACTPROB
CHARACTER*8 FILENAME
CHARACTER*8 DECKANME
INTEGER*4 ONECOEF
END FUNCTION

INTEGER*4 FUNCTION WFLOAD  ( ACTFILE, ACTPROB )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFLOAD
!DEC$ATTRIBUTES REFERENCE ::  ACTFILE, ACTPROB
CHARACTER*8 ACTFILE
CHARACTER*8 ACTPROB
END FUNCTION
```

```
INTEGER*4 FUNCTION WFOPT   ( )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFOPT
END FUNCTION

INTEGER*4 FUNCTION WFEND   ( )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFEND
END FUNCTION

INTEGER*4 FUNCTION WFCVAL  ( COLNAME, ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCVAL
!DEC$ATTRIBUTES REFERENCE ::  COLNAME, ROWNAME, VALUE
character*8 COLNAME
character*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFCRHS  ( ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCRHS
!DEC$ATTRIBUTES REFERENCE ::  ROWNAME, VALUE
character*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFCRNG  ( ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCRNG
!DEC$ATTRIBUTES REFERENCE ::  ROWNAME, VALUE
CHARACTER*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFCBND  ( COLNAME, LOBOUND, UPBOUND )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCBND
!DEC$ATTRIBUTES REFERENCE ::  COLNAME, LOBOUND, UPBOUND
character*8 COLNAME
REAL*8 LOBOUND
REAL*8 UPBOUND
END FUNCTION

INTEGER*4 FUNCTION WFRVAL  ( COLNAME, ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRVAL
!DEC$ATTRIBUTES REFERENCE ::  COLNAME, ROWNAME, VALUE
character*8 COLNAME
character*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFRRHS  ( ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRRHS
!DEC$ATTRIBUTES REFERENCE ::  ROWNAME, VALUE
character*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFRRNG  ( ROWNAME, VALUE )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRRNG
!DEC$ATTRIBUTES REFERENCE ::  ROWNAME, VALUE
CHARACTER*8 ROWNAME
REAL*8 VALUE
END FUNCTION

INTEGER*4 FUNCTION WFRBND  ( COLNAME, LOBOUND, UPBOUND )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRBND
```

```
!DEC$ATTRIBUTES REFERENCE ::  COLNAME, LOBOUND, UPBOUND
character*8 COLNAME
REAL*8 LOBOUND
REAL*8 UPBOUND
END FUNCTION

INTEGER*4 FUNCTION WFRLVAL ( COLNAME, START, INDEX, VALUE, COUNT)
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRLVAL
!DEC$ATTRIBUTES REFERENCE ::  COLNAME, START, INDEX, VALUE, COUNT
INTEGER*4 COLNAME
INTEGER*4 START
INTEGER*4 INDEX(*)
REAL*8 VALUE(*)
INTEGER*4 COUNT
END FUNCTION

INTEGER*4 FUNCTION WFRNAME ( INDEX, NAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRNAME
!DEC$ATTRIBUTES REFERENCE ::  INDEX, NAME
INTEGER*4 INDEX
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION WFCNAME ( INDEX, NAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCNAME
!DEC$ATTRIBUTES REFERENCE ::  INDEX, NAME
INTEGER*4 INDEX
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION WFRMASK ( MASK, NAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRMASK
!DEC$ATTRIBUTES REFERENCE ::  MASK, NAME
CHARACTER*8 MASK
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION WFCMASK ( MASK, NAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFCMASK
!DEC$ATTRIBUTES REFERENCE ::  MASK, NAME
CHARACTER*8 MASK
CHARACTER*8 NAME
END FUNCTION

INTEGER*4 FUNCTION WFSROW  ( NAME, SELECT, STAT, SOLVAL )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFSROW
!DEC$ATTRIBUTES REFERENCE ::  NAME, SELECT, STAT, SOLVAL
CHARACTER*8 NAME
CHARACTER*8 SELECT
character*2 STAT
REAL*8 SOLVAL(2)
END FUNCTION

INTEGER*4 FUNCTION WFSCOL  ( NAME, SELECT, STAT, SOLVAL )
!DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFSCOL
!DEC$ATTRIBUTES REFERENCE ::  NAME, SELECT, STAT, SOLVAL
CHARACTER*8 NAME
CHARACTER*8 SELECT
character*2 STAT
REAL*8 SOLVAL(2)
END FUNCTION

INTEGER*4 FUNCTION WFRROW  ( NAME, SELECT, STAT, SOLVAL )
```

```
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRROW
!DEC$ATTRIBUTES REFERENCE :: NAME, SELECT, STAT, SOLVAL
INTEGER*4 NAME
CHARACTER*8 SELECT
character*2 STAT
REAL*8 SOLVAL
END FUNCTION


INTEGER*4 FUNCTION WFRCOL ( NAME, SELECT, STAT, SOLVAL )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRCOL
!DEC$ATTRIBUTES REFERENCE :: NAME, SELECT, STAT, SOLVAL
INTEGER*4 NAME
CHARACTER*8 SELECT
character*2 STAT
REAL*8 SOLVAL
END FUNCTION


INTEGER*4 FUNCTION WFRLIST ( LIST, COUNT )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRLIST
!DEC$ATTRIBUTES REFERENCE :: LIST, COUNT
CHARACTER*8 LIST
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION WFCLIST ( LIST, COUNT )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFCLIST
!DEC$ATTRIBUTES REFERENCE :: LIST, COUNT
CHARACTER*8 LIST
INTEGER*4 COUNT
END FUNCTION


INTEGER*4 FUNCTION WFSPRT ( ACTIVE )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFSPRT
!DEC$ATTRIBUTES REFERENCE :: ACTIVE
INTEGER*4 ACTIVE
END FUNCTION


INTEGER*4 FUNCTION WFSFILE ( FILENAME, ACTIVE )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFSFILE
!DEC$ATTRIBUTES REFERENCE :: FILENAME, ACTIVE
CHARACTER*8 FILENAME
INTEGER*4 ACTIVE
END FUNCTION


INTEGER*4 FUNCTION WFRCORD ( ACTFILE, ACTPROB, CASENAME, ACTIVE )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRCORD
!DEC$ATTRIBUTES REFERENCE :: ACTFILE, ACTPROB, CASENAME, ACTIVE
CHARACTER*8 ACTFILE
CHARACTER*8 ACTPROB
CHARACTER*8 CASENAME
INTEGER*4 ACTIVE
END FUNCTION


INTEGER*4 FUNCTION WFRPRT ( )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRPRT
END FUNCTION


INTEGER*4 FUNCTION WFRFILE ( FILENAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFRFILE
!DEC$ATTRIBUTES REFERENCE :: FILENAME
CHARACTER*8 FILENAME(*)
END FUNCTION
```

```
INTEGER*4 FUNCTION WFSAVEB ( FILENAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFSAVEB
!DEC$ATTRIBUTES REFERENCE :: FILENAME
CHARACTER*8 FILENAME(*)
END FUNCTION

INTEGER*4 FUNCTION WFLOADB ( FILENAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFLOADB
!DEC$ATTRIBUTES REFERENCE :: FILENAME
CHARACTER*8 FILENAME(*)
END FUNCTION

INTEGER*4 FUNCTION WFPUNCH ( FILENAME, DECKANME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFPUNCH
!DEC$ATTRIBUTES REFERENCE :: FILENAME, DECKANME
CHARACTER*8 FILENAME
CHARACTER*8 DECKANME
END FUNCTION

INTEGER*4 FUNCTION WFINSRT ( FILENAME, DECKANME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFINSRT
!DEC$ATTRIBUTES REFERENCE :: FILENAME, DECKANME
CHARACTER*8 FILENAME
CHARACTER*8 DECKANME
END FUNCTION

INTEGER*4 FUNCTION WFMGDMP ( MODEL, WMGNAME, KEEPFAC )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFMGDMP
!DEC$ATTRIBUTES REFERENCE :: MODEL, WMGNAME, KEEPFAC
REAL*8 MODEL(*)
CHARACTER*8 WMGNAME
INTEGER*4 KEEPFAC
END FUNCTION

INTEGER*4 FUNCTION WFMGLOD ( MODEL, WMGNAME, MODLNAME )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFMGLOD
!DEC$ATTRIBUTES REFERENCE :: MODEL, WMGNAME, MODLNAME
REAL*8 MODEL(*)
CHARACTER*8 WMGNAME
CHARACTER*8 MODLNAME
END FUNCTION

INTEGER*4 FUNCTION WFCRGET ( NAME, VALUE, VLEN, ALEN )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFCRGET
!DEC$ATTRIBUTES REFERENCE :: NAME, VALUE, VLEN, ALEN
CHARACTER*8 NAME
INTEGER*4 VALUE
INTEGER*4 VLEN
INTEGER*4 ALEN
END FUNCTION

INTEGER*4 FUNCTION WFCRPUT (COMMAND,NAME,VALUE,STRING,VERBOSE)
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFCRPUT
!DEC$ATTRIBUTES REFERENCE :: COMMAND,NAME,VALUE,STRING,VERBOSE
CHARACTER*8 COMMAND
CHARACTER*8 NAME
INTEGER*4 VALUE
INTEGER*4 STRING
INTEGER*4 VERBOSE
END FUNCTION

INTEGER*4 FUNCTION WFALLOC ( MODEL, LEN )
!DEC$ATTRIBUTES STDCALL, REFERENCE :: WFALLOC
```

```
          !DEC$ATTRIBUTES REFERENCE ::  MODEL, LEN
          REAL*8 MODEL(*)
          INTEGER*4 LEN
          END FUNCTION

          SUBROUTINE WFFREE        ( MODEL, LEN )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFFREE
          !DEC$ATTRIBUTES REFERENCE ::  MODEL, LEN
          REAL*8 MODEL(*)
          INTEGER*4 LEN
          END SUBROUTINE

          INTEGER*4 FUNCTION WFRDCR  ( CRFILE )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFRDCR
          !DEC$ATTRIBUTES REFERENCE ::  CRFILE
          CHARACTER*8 CRFILE
          END FUNCTION

          INTEGER*4 FUNCTION WFWRCR  ( CRFILE )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFWRCR
          !DEC$ATTRIBUTES REFERENCE ::  CRFILE
          CHARACTER*8 CRFILE
          END FUNCTION

          INTEGER*4 FUNCTION WCWRCR  ( CRFILE )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WCWRCR
          !DEC$ATTRIBUTES REFERENCE ::  CRFILE
          CHARACTER*8 CRFILE
          END FUNCTION

          INTEGER*4 FUNCTION WFM2ACT ( ACTFILE,ACTPROB )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFM2ACT
          !DEC$ATTRIBUTES REFERENCE ::  ACTFILE,ACTPROB
          CHARACTER*8 ACTFILE
          CHARACTER*8 ACTPROB
          END FUNCTION

          SUBROUTINE WFSYSPR       ( FMT )
          !DEC$ATTRIBUTES STDCALL, REFERENCE ::  WFSYSPR
          !DEC$ATTRIBUTES REFERENCE ::  FMT
          CHARACTER*8 FMT
          END SUBROUTINE
!
          subroutine PICK (CASEKEY, PICKRG, PICRTN, I)
          !DEC$ATTRIBUTES STDCALL, REFERENCE :: pick
          integer*2 casekey(*)
          integer*4  pickrg(*)
          integer*4  picrtn(*)
          integer*4  i
          END SUBROUTINE

          subroutine FIND (CASEKEY, Ival, SL, Jval, I)
          !DEC$ATTRIBUTES STDCALL, REFERENCE :: find
          integer*2 casekey(*)
          integer*4  sl(*)
          integer*4  i,ival,jval
          END SUBROUTINE

          END INTERFACE
          integer icrloc
          TYPE (CR) :: OML
          POINTER (icrloc,OML)
          common/wcr/icrloc
```

Appendix G-E: MRM Data Conversion

Most of the current data used in the MRM were last updated using the Jun2003 data (referred to as ENSYS03Jun) provided by EnSys Company. (No updates using Ensys data were made for *AEO2005* or *AEO2006*.) Due to the differences in data format (OMNI vs OML) and naming conventions, the ENSYS03Jun data had to undergo conversion; and, new mapping data tables had to be added to the MRM files prior to being used by the MRM.

The updated OMNI data files provided by ENSYS and used to update the mrm data tables are located in the directory m:/ogs/pmm_prj/ensys/ensys03_Jun/data/ , and include:

  R-GCB.DAT
  R-MPROC.DAT
  R-NPROC1.DAT
  R-NPROC2.DAT
  R-PROC1.DAT
  R-PROC2.DAT
  Table INUNIT Revised 0703.xls

The following provides a summary of the effort it took to convert the ENSYS03Jun OMNI data tables (*.DAT) into OML RTB tables (to be read by the matrix generation code). A shareware c-compiler called LCC-win32 was used. The omni2rtb.c program is located in the directory m:/ogs/pmm_prj/ensys/ ensys03_Jun/source/. The c-compiler may be installed on a local PC by executing the installation program M:\ogs\pmm_prj\C-Compiler\LCC-Win32.exe.

To compile on the PC:

1. Put the omni2rtb.c file in the directory you want to run from:
  c:\Documents and Settings\EM4\mydocs\c-test\

2. From the START menu, click on Programs, lcc-win32, lcc-win32.exe

3. From within the LCC program window, OPEN the omni2rtb.c file located in the c-test directory.

4. If no changes are needed, click on the COMPILER menu and select REBUILD ALL. This will create an omni2rtb.exe file in a new lcc directory within the c-test directory.

To execute on the PC:

1. Go to the newly created lcc directory, put the Ensys *.DAT files into this directory, and open a DOS window (Command Prompt). In this window, move to the ...c-test/lcc/ directory and type

  omni2rtb <input file path/name> <output file path/name>

  ie., omni2rtb R-GCB.DAT gcb.out

Note: prior to the AEO2003 effort, the following methodology was used from the RS6000 using a c-compiler on that platform.

1. *The code to convert the OMNI tables to RTB tables is called omni2rtb.c and can be found in directory m:/ogs/pmm_prj/ensys/ensys01-feb/source01/ (on the EIA NT server).*

2. *To compile and execute the omni2rtb type:*
   compile: cc -o <exec filename> <source code filename>
   execute: <exec filename> <input data path/filename> <output filename>

   For example, if all files are in the same directory:
   cc -o omniexec omni2rtb.c
   omniexec v0.ensrymeq.gdb omniout

3. *Technology database development since 1994, according to Ensys:*
   - *Implementation of weight balancing on every process vector*
   - *Implementation of rigorous sulfur balancing on every process vector (down to the ppm level)*
   - *Conversion of the technology database to spreadsheet basis (Excel)*
   - *Implementation of model compositing system. This current task is directed to RYM-type regional/prototypical refinery fuels/regulatory studies and takes advantage of the fact that, in any one case, crude slate is essentially fixed. This enables a much smaller matrix to be generated, with yields and qualities crude slate dependent, from the un-composited model tables. Resulting model matrix has far fewer prototypical streams, less susceptibility to over-optimization (and attendant criticism), more manageable when ratio controls are used. (The task to develop this system is proving to be a rigorous diagnostic on model structure, non-composited and composited, and as such is helping eliminate any errors.)*

The following list of *.dat and tables were updated using the new ensys03Jun data:

DISTBLND.DAT
    T:DCC
    T:DCB
GASOBLND.DAT
    T:GCB
    T:GCC
    T:MCO
    T:REGBV
    T:LOGBV
    T:PRMBV
    T:PRCBV
    T:UNLBV
    T:UNCBV
    T:RFMBV
    T:RGBBV
    T:RGCBV
MCHPROC.DAT
    T:C4XREP,T:C4XCAP,T:C4XPOL,T:C4XUTI
    T:ETXREP,T:ETXCAP,T:ETXPOL,T:ETXUTI
    T:FUXREP,T:FUXCAP,T:FUXPOL,T:FUXUTI
    T:IOXREP,T:IOXCAP,T:IOXPOL,T:IOXUTI

T:OLXREP,T:OLXCAP,T:OLXPOL,T:OLXUTI
T:SMDREP,T:SMDCAP,T:SMDPOL,T:SMDUTI
T:SODREP,T:SODCAP,T:SODPOL,T:SODUTI
RECIPES.DAT
    T:RCP
REFPROC.DAT
    T:MATBAL
    T:SCL
    T:(uns)
    T:INVGEN
    T:INVUNT
STREAM.DAT
    T:TRS

Appendix G-F: Refinery Processes

Refinery Process	Abbreviation
Atmospheric crude distillation	ACU
Atmospheric Residuum Desulfurization	ARD****
Aromatic recovery	ARP
C2E to C4E dimerization	C24*
Butane isomerization	C4I
Butane splitter	C4S**
Alkylation feed butene isomerizer	C4T*
Butane isomerization	C4X***
Catalytic Distillation Technology	CDT
Cogeneration unit	CGN**
Cogeneration unit, merchant	CGX**
Combined Heat/Power burning syngas fr Pet Coke	CHP**
Polymerization	CPL
Coal to Liquids process	CTX, CTZ
Cyclar	CYC
Distillate desulfurizer	DDS
Gas oil dewaxer	DEW
Dimersol	DIM
Etherol	ETH, ETM
Cryogenic C2 fractionation	ETS*
Etherol unit	ETX***
Fluid cat cracker	FCC
FCC feed hydrofiner	FDS
Mid-distillate furfural treating	FEX
FCC gasoline fractionation units	FGS
Fuel plant	FUM**
Fuel plant	FUX***
Petroleum Coke gasification (produces syngas)	GSF
Petroleum Coke gasification (produces hydrogen)	GSH
Hydrogeneration normal pentenes/hexenes	H56*

Refinery Process	Abbreviation
H2-stream reformer	H2P
H2-partial oxidizer	H2X
Low Conversion Hydrocracking	HCL****
Hydrocracker (partial)	HCM (old MAK)
Naphta hydrocracker	HCN
Gas oil hydrocracker	HCR
Hydrocracker (GasOil)- advanced technology	HCU
Residum hydrocracker	HCV
Hydrodesulfurizer 1	HD1****
Hydrodesulfurizer 2	HD2, HS2****
High density jet fuel hydrotreating	HDN
Hydrofluoric Acid Alkylation	HFA
Hydrogen/fuel gas reformer hydrogen	HLO**
Hydrogen Purification	HPM
Iso-octane unit converted from MTBE	IOT
Iso-octane unit converted from MTBE, merchant	IOX
High density jet fuel prefactionation	JFP
Recut for JTA	JPS**
Delayed-coker	KRD
Fluid/flexi-coker	KRF
Power generation	KWG**
Lub and wax	LUB
Olefin Saturation Process (MOH fr Ensys)	MDH****
Catalytic Fluidized Bed	MOD****
Naphtha hydrotreater	NDS
OCTGAIN Catalytic Hydroprocessor	OCT
C2-C5 dehydrogenation	OLE*
C2-C5 dehydrogenation	OLX***
Produced Fuel Adjustment	PFA**
Pentane/hexane isomerization	PHI
Phillips S zorb	PHS
Prism Pressure Swing Absorption- H_2 Purification	PSA

Refinery Process	Abbreviation
Hydrodesulfurization (S-Zorb) for diesel	PSZ
Residuum desulfurizer	RDS
Refinery Loss	REL**
LP continuous reformer	RFC
HP semi-regenerative reformer	RFH
LP cyclic reformer	RFL
Solvent deasphalting	SDA
Sulfuric Acid Alkylation	SFA
Shell Middle Distillate	SMD
Syntroleum GTL Process	SOD
Caustic SOx Scrubber	SOX****
Naphtha splitter	SPL
Steam generation, lbs/hr	STG**
Sulfur, short tons/day	SUL
Sulphco Selective Oxydation	SUP
Mid-distillate deep hydrotreater	SYD
Thermal cracker C2-C4 feed	TCG*
Thermal cracker naphta feed	TCN*
Thermal cracker gas oil feed	TCV*
Total recycle isomerization	TRI*
Visbreaker/thermal cracker	VBR
Vacuum distillation	VCU

* : Processes involved in reformulated gasoline manufacturing
**: Utilities and pseudo-units
***: Processes represented in OXY-Refineries
****: Not made available for *AEO2005*-- new, not ready for production

APPENDIX H

Historical Data Processing

APPENDIX H. Historical Data Processing

H.1 Processing Data for PMM History File

The PMM uses historical data from a variety of sources. The Microsoft Access database "Build Elgcpur.mdb" collects and aggregates this data to prepare the PMM input file Elcgpur.txt. The three principle databases it collects from (see Figure H.1) are the Oil and Gas Information Reporting System (OGIRS) which contains most historical wholesale price and volume information, the Non-Utility Generators (NUGs) database which contains refinery co-generation information, and the Short-Term Integrated Forecasting System (STIFS) database which contains data from the end of the historical period until the PMM forecast is available. Additional individual data elements are added as tables to the Elcgpur.mdb database as described below.

Figure H.1   Database Linkages
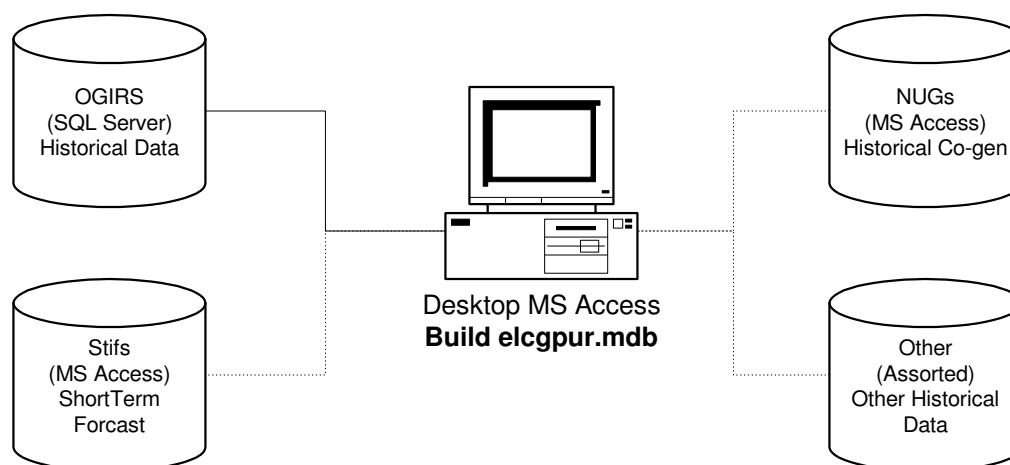
Accessing Data:

The file "Build Elcgpur.mdb" currently resides in the PMM Project folder on nems-f8 ("M" drive) in the folder M:\ogs\pmm_prj\Database\History (History folder). The following explains how to connect to the component databases that are used in processing the historical input file.

1)   OGIRS: The OGIRS database is called via a short Visual Basic Application (VBA) script called "modOgirsFunction." This script searches the table "tblParkList" for the OGIRS keys and frequency of the data required to form a request to the main OGIRS server. Executing this function creates the local table "dbo_Ogidata" (**Ogidata**) with all data for the requested keys and frequency.

For example, to pull annual data for kerosene-based jet fuel production for all the U.S. PAD Districts enter the OGIRS Sourcekeys for the data series in the Sourcekey column and an "A" (for annual) in the "FrqncName" column as shown in Table H.1 . While it is unnecessary to complete the "SERIES" field, having a local reference to the Sourcekey definition is advisable. A partial list of Sourcekeys available can be found in the database "OGIRS keys.mdb" in the History folder.

Table H.1 Park List Sample

SOURCEKEY	SERIES	FrqncName
MKJRPP12	PADD I Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP22	PADD II Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP32	PADD III Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP42	PADD IV Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP52	PADD V Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPUS2	US Jet Fuel Kero Refinery Production (Mbbl/d)	A

Most of data used by PMM is pulled from OGIRS as an annual number. The only time monthly data are used is for the computation of Refinery Operable Capacity. For this value the January data are used to record the previous year's capacity.

The OGIRS database is mostly complete; however, there are a few missing fields in the database. To prevent errors from occurring when the queries are executed, the short list of missing values can be appended to **Ogidata** by running the query "Add Missing Keys to data." This query pulls known missing data[1] from the table "Missing Keys." An even rarer occurrence is when data are incorrect in OGIRS. Should this be discovered, the correct values can be placed in the table "Data Errors" which will update **Ogidata** when the query "Update data" is executed. All new missing or incorrect data should be reported to the OGIRS database administrator (currently Jaime Chan 202-586-1515). It is also worthwhile to check that keys are, in fact, still missing. The query "Check still missing" will display any duplicate keys in **Ogidata.**

Assuming correct entries in the tables "Missing Keys" and "Data Errors," the entire download process can accomplished automatically by running the "Update From OGIRS and add missing Keys" Macro.

2)   STIFS: The Current Month's Stifs database is located on the EIA LAN at: \\fs-f1\L6489\PRJ\STEO Web Query Database\stifs.mdb. Assistance in obtaining access to this file can be arranged with Tancred Lidderdale (202-586-7321). After obtaining a local copy (typically stored in the History directory), open "Build Elcgpur.mdb" and from the "Tools" menu select "Data base Utilities" and then Linked table manager. Check the tables "Dates" and "Table_PA" and the box "prompt for new location." Click OK and Browse to the location of Stifs.mdb. This enables the database to extract the latest STEO database.

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[1] The last version of OGIRS is missing some of the elements of refinery production: nfrpp1-p5(naphtha feedstocks), otrpp1-p5 (other oils for feedstock), msrpp1-us(miscellaneous products for non-fuel use), and pfrp-us(total petrochemical feedstocks).

3)   NUGs: An connection to the Coal Nuclear and Electric and Alternate Fuels Oracle "feeder" database housing the final non-utility generation information has been established. This tables are "linked" in the manner described above to the file "Nugs.mdb" which manipulates this data to extract refinery specific data. Each of the flowing tables then becomes a linked table to "Build Elcgpur.mdb."

1- Gen Grid

2- Gen Own

3- Grid Gen Cap

4- Own Gen Cap

5- Data Grid Fuel Use

6- Data Own Fuel Use

7- Tbl Grid Gen Percent

4)   Other Data: Additional sources are used for creation of the PMM history data file.

a) Manually update fuel consumption data in Table 47 of the *Petroleum Supply Annual* to table "PSA Table 47."

b) Global Database Variables: STEOYEAR, HISOYEAR, and STEOYEARS must be reset each year the History file generator is used. Running the Macro "STEO-HISTO" will prompt the user to enter the last Historical information year and the remaining keys will be updated automatically.

c) Index for GDP Price deflators for the forecast period are stored in table "GDP87." These are generally updated each year by the Macro team and can be found in Table 101 of the Ftab report.

d) Ethanol plant energy costs are derived by Tony Radich (202-586-0504) and stored in Table "Ethanol Energy Costs."

e) Historical Petroleum Product Prices are from the *State Energy Data 2000: Prices (SEDP)* and stored in the "Product price data" Table. For *AEO2005,* aggregated CD level data from the previous year was used through 2001. For years 2002 through 2005 these prices were scaled by the change in the equivalent national numbers reported in the September 2004 *Short Term Energy Outlook*.

Data Processing Queries:

After all the data from the different sources have been input (or linked) to the database several queries (see examples in Figure H.2) are executed to manipulate the data into PMM variables. The numbers correspond

with the position of the variable being generated in the Elcgpur.txt file. This code should not need to be changed absent a change in the definition of PMM variable it represents. Should this occur the individual variable query can be examined and edited.

Figure H.2   Sample Database Queries

PMM variables are linked to variables in input databases (primarily OGIRS and STIFS) by table "Map PMM to OGIRS." A complete list of mappings for both historical and STEO years is available in Table H1. Multiple entries for a PMM variable indicate that more than one OGIRS or STEO variable is needed to calculate the value for these variables. The multiple entries are summed to obtain the PMM variable. For example the OGIRS keys for RFPRDOTH are the sum of the keys in that row (Aviation Fuel, Lubes, Naphtha, and Waxes). In the case where a (-) appears before a variable, the key is multiplied by -1 before summation. A "Δ" before a key refers to the difference between the current and previous years value for that key.

Table H.2 Components of PMM Variables

PMM Variable	Definition	Historical Years	Description	STEO Years
RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
RFQICRD	CRUDE IMPORTS IN MMBD	OGIRS- MCRIMPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Imports (Mbbl/d)	CONXPUS use last historical year % to parse to PADDs
RFPQNGL	NGL PRODUCTION IN MMBD	OGIRS- MLPSNPx1 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Field Production (Mbbl/	NLPRPUS use last historical year % to parse to PADDs
RFBDSTCAP	BASE DISTILLATION CAPACITY MBCD	OGIRS- MOCLEPx1 (Where x is PADD#)	PADD x Averages/Totals Refinery Operable Capacity (Mbbl/d) - January Value	Not available use most recent historical year -proxy: CODIPUS
RFDSTUTL	DIST UTILIZATION RATE IN MBD	OGIRS- MOPUEPx2 (Where x is PADD#)	PADD x Averages/Totals Other Petroleum Products % Utilization Ref	CODIPUS/Last historical years Capacity
RFQEXPRDT	PRODUCT EXPORTS IN MMBD	OGIRS- MTTEXPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Petroleum Products Exports (Mbbl/d)	Last years exports of Petroleum Products
		(-)OGIRS-MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	
RFPQIPRDT	PRODUCT IMPORTS IN MMBD	OGIRS- MTPIMPx2 (Where x is PADD#)	PADD x Finished Petroleum Products Imports (Mbbl/d)	PANIPUS
		OGIRS- MNGIMPx2 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Imports (Mbbl/d)	Last years exports of Petroleum Products
RFDPRDAST (AST)	Asphalt Refinery Production (Mbbl/d)	OGIRS- MAPRPPx2 (Where x is PADD#)	PADD x Asphalt Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDCOK (COK)	Pet Coke Refinery Production (Mbbl/d)	OGIRS- MCKRPPx2 (Where x is PADD#)	PADD x Petroleum Coke Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDJTA (JTA)	Jet Fuel Kero Refinery Production (Mbbl/d)	OGIRS- MKJRPPx2 (Where x is PADD#)	PADD x Jet Fuel Kero Refinery Production (Mbbl/d)	JFROPUS* Last Histo Year PADD Splits
RFDPRDKER (KER)	Kerosene Refinery Production (Mbbl/d)	OGIRS- MKERPx2 (Where x is PADD#)	PADD x Kerosene Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDLPG (LPG)	Refinery production; LPG	OGIRS- MLPRPPx2 (Where x is PADD#)	PADD x Liquefied Petroleum Gases Refinery Production (Mbbl/d)	LGROPUS* Last Histo Year PADD Splits
RFDPRDN2H (N2H)	Refinery prd; no. 2 distillate	OGIRS- MDIRPPx2 (Where x is PADD#)	PADD x Total Distillate Refinery Production (Mbbl/d)	DFROPUS* Last Histo Year PADD Splits
RFDPRDN6B (N6B)	Refinery prd; high sulfur oil	OGIRS- MRGNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Net Production (Mbbl)	RFROPUS*Histo year Sulfur Split and PADD
RFDPRDN6I (N6I)	Refinery prd; low sulfur resid oil	OGIRS- MRLNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur 0-0.3 Net Production (Mbbl/d)	RFROPUS*Histo year Sulfur Split and PADD
		OGIRS- MRMNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur .31-100 Net Production (Mbbl/d)	
RFDPRDOTH (OTH)	Refinery prd; other petroleum	OGIRS- MGARPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Refinery Production (Mbbl/d)	Use 10 year average growth
		OGIRS- MLURPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Refinery Production (Mbbl/d)	
		OGIRS- MNSRPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Refinery Production (Mbbl/d)	
		OGIRS- MWXRPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Refinery Production (Mbbl/d)	
RFDPRDPCF (PCF)	Refinery prd; petrochemical feeds	OGIRS- MPFRPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDSTG (STG)	Refinery prd; still gas	OGIRS- MSGRPPx2 (Where x is PADD#)	PADD x Still Gas Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDTRG (TRG)	Refinery prd; motor gasoline	OGIRS- MGFRPPx2 (Where x is PADD#)	PADD x Finished Gasoline Refinery Production (Mbbl/d)	MGROPUS* Last Histo Year PADD Splits
RFQDCRD	Unaccounted crude	OGIRS- MCRAUPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Unaccounted for (Mbbl/d)	COUNPUS
CRDSTWDR	Crude stock withdrawals	OGIRS- MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	CONQPUS ΔCOSXPUS/365
CRDPRDSUP	Crude product withdrawals	OGIRS- MCRUPPx2	PADD x Averages/Totals Crude Oil Product Supplied (Mbbl/d)	0
RFQPRCG1	PROCESSING GAIN IN MMBD	OGIRS- MPGNPUS1/365	US Processing Gain Net Production (Mbbl)	PAGLPUS
BLDIMP	Blending component imports	OGIRS- MBCIMUS2	US Blending Components Gasoline Imports (Mbbl/d)	MBNIPUS
BLDPRD	Product blending component	OGIRS- MBCFPUS2	US Blending Components Gasoline Field Producion (Mbbl/d)	MBFPPUS
NGLRF	NGL from refinery	OGIRS- MNGRIUS2	US Natural Gas Liquids and LRGs Totals Input into Refineries (Mbbl/d)	LGRIPUS PPRIPUS
OTHOXY	Other oxygenates	OGIRS- MOHFPUS2	US Other Hydrocarbons/Oxygenates Field Production (Mbbl/d)	OHRIPUS
PRDSTKWDR	Product stocks withdrawals	OGIRS- MTTSCUS2	United States Total Crude Oil and Petroleum Products Stock Change (Mbbl/d)	Assume Zero
		(-)OGIRS-MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	
RFETHE85	Ethanol for E85 production	Hart	Oxy Fuel News Data	Oxy Fuel News Data
RFETHMGS	Ethanol for motor gasoline	OGIRS- OFETPUS2	US Oxygenates Fuel Ethanol Production (Mbbl/d)	EOFPPUS
RFMETETH	Methanol for ether	Historical Quantities not tracked	Zeros	Assume Zero
RFMTBI	Imported MTBE	OGIRS- MMTIMUS2	US Oxygenates MTBE Imports (Mbbl/d)	Assume Zero
RFPQUFC	Total imports of unfinished crude	OGIRS- MUOIMUS2	US Unfinished Oils Imports (Mbbl/d)	UORIPUS
RFSPRFR	SPR fill rate	OGIRS- -MCSSCUS1/365	US Crude Oil Stock Change SPR (Mbbl)	CONQPUS
AST	Asphalt Product Supplied (Mbbl/d)	OGIRS- MAPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Asphalt Product Supplied (Mbbl/d)	ARTCPUS
COK	Petroleum Coke Product Supplied (Mbbl/d)	OGIRS- MCKUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Coke Product Supplied (Mbbl/d)	PCTCPUS
JTA	Jet Fuel Kero Product Supplied (Mbbl/d)	OGIRS- MKJUPPx2 (Where x is PADD#)	PADD x Averages/Totals Jet Fuel Kero Product Supplied (Mbbl/d)	JFTCPUS
KER	Kerosene Product Supplied (Mbbl/d)	OGIRS- MKERUPPx2 (Where x is PADD#)	PADD x Averages/Totals Kerosene Product Supplied (Mbbl/d)	KSTCPUS
LPG	Product Supplied; LPG	OGIRS- MLPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Liquefied Petroleum Gases Product Supplied (Mbbl/d)	LGTCPUS
N2H	Product Supplied; no. 2 distillate	OGIRS- MDIUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Distillate Product Supplied (Mbbl/d)	DFTCPUS
N6B	Product Supplied; high sulfur oil	Computed- MRSUPHx2 (Where x is PAD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Product Supplied (Mbbl/d)	RFTCPUS * High%
N6I	Product Supplied; low sulfur residual oil	Computed- MRSUPLx2 (Where x is PAD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur < 1.0 Product Supplied (Mbbl/d)	RFTCPUS* Low%
OTH	Product Supplied; other petroleum	OGIRS- MGAUPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Product Supplied (Mbbl/d)	AVTCPUS
		OGIRS- MLUUPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Product Supplied (Mbbl/d)	LUTCPUS
		OGIRS- MNSUPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Product Supplied (Mbbl/d)	SNTCPUS
		OGIRS- MWXUPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Product Supplied (Mbbl/d)	WXTCPUS
PCF	Product Supplied; petrochemical feeds	OGIRS- MPFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Product Supplied (Mbbl/d)	FETCPUS
STG	Product Supplied; still gas	OGIRS- MSGUPPx2 (Where x is PADD#)	PADD x Averages/Totals Still Gas Product Supplied (Mbbl/d)	SGTCPUS
RFQPRDT	Total product supplied	OGIRS- MTTUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Pet Products Supplied (Mbbl/d)	Sum STEO Product Quantities
		(-)OGIRS-MCRUPPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Product Supplied (Mbbl/d)	
TRG	Product Supplied; motor gasoline	OGIRS- MGFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Finished Gasoline Product Supplied (Mbbl/d)	MGTCPUS
QELETH	Historical Electricity use at Ethanol plants -		Multiply EOFPPUS ethanol production by Tony Radich's formulas for energy consumption	
QNGETH	Historical Nat Gas use at Ethanol plants			

Table H.2 Components of PMM Variables

PMM Variable	Definition	Historical Years	Description	STEO Years
QCLETH	Historical Coal use at Ethanol plants			
QCLRF	Refinery Fuel –Coal	Paste in from table 47 of PSA	Use In MMBTU	
QDSRF	Refinery Fuel -Distillate Fuel Oil	Paste in from table 47 of PSA	Use In MMBTU	
QELRF	Refinery Fuel -Purchased Elec.	Paste in from table 47 of PSA	Use In MMBTU	
QLGRF	Refinery Fuel –LPG	Paste in from table 47 of PSA	Use In MMBTU	Assume last Historical Year ratio of fuel to production Average refiner price of residual fuel oil
QNGRF	Refinery Fuel -Nat Gas	Paste in from table 47 of PSA	Use In MMBTU	
QOTRF	Refinery Fuel –Other	Paste in from table 47 of PSA	Use In MMBTU	
QPCRF	Refinery Fuel -Pet Coke	Paste in from table 47 of PSA	Use In MMBTU	
QRSRF	Refinery Fuel -Residual Fuel	Paste in from table 47 of PSA	Use In MMBTU	
QSGRF	Refinery Fuel -Still Gas	Paste in from table 47 of PSA	Use In MMBTU	
PASIN	Asphalt, Road Oil, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PDSCM	Distillate, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSEL	Distillate, Electricity (+petroleum coke)		PRODUCT PRICES IN 87$ PER MMBTU	PRODUCT PRICES IN 87$ PER MMBTU
PDSIN	Distillate, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSRS	Distillate, Residential		PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSTR	Distillate, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PJFTR	Jet Fuel, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSCM	Kerosene, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSIN	Kerosene, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSRS	Kerosene, Residential		PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PLGCM	Liquid Petroleum Gases, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGIN	Liquid Petroleum Gases, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGRS	Liquid Petroleum Gases, Residential		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGTR	Liquid Petroleum Gases, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PMGCM	Motor Gasoline, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGIN	Motor Gasoline, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGTR	Motor Gasoline, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PPFIN	Petrochemical Feedstocks, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PRHEL	Residual Fuel, High Sulfur, Electricity		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRHTR	Residual Fuel, High Sulfur, Transp.		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLCM	Residual Fuel, Low Sulfur, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLEL	Residual Fuel, Low Sulfur, Electricity		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLIN	Residual Fuel, Low Sulfur, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
OG GEN GRID90	COGENERATION IN MMBTU			
PT GEN GRID90	COGENERATION IN MMBTU			
NG GEN GRID90	COGENERATION IN MMBTU			
OT GEN GRID90	COGENERATION IN MMBTU			
OG GEN OWN 90	COGENERATION IN MMBTU			
PT GEN OWN 90	COGENERATION IN MMBTU			
NG GEN OWN 90	COGENERATION IN MMBTU			
OT GEN OWN 90	COGENERATION IN MMBTU			
OG CAP GRID90	Capacity MW			
PT CAP GRID90	Capacity MW			
NG CAP GRID90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT CAP GRID90	Capacity MW			
OG CAP OWN 90	Capacity MW			
PT CAP OWN 90	Capacity MW			
NG CAP OWN 90	Capacity MW			
OT CAP OWN 90	Capacity MW			
OG FUL GRID90	Cogen Fuel consumption			
PT FUL GRID90	Cogen Fuel consumption			
NG FUL GRID90	Cogen Fuel consumption			
OT FUL GRID90	Cogen Fuel consumption			
OG FUL OWN 90	Cogen Fuel consumption			
PT FUL OWN 90	Cogen Fuel consumption			
NG FUL OWN 90	Cogen Fuel consumption			
OT FUL OWN 90	Cogen Fuel consumption			
DCRDWHP	WELLHEADD CRUDE OIL PRICES	From Ted McCallister's Calculations.	IN $/BBL	Assume Region's price changes as Δ of WOP
RFQDCRD	CONVENTIONAL CRUDE PRODUCTION		IN MBD	Assume Region's Production changes as Δ of COPRPUS
RFQTDCRD	TOTAL CRUDE PRODUCTION		IN MMBD	Assume Region's Production changes as Δ of COPRPUS

Creating PMM Flat-file:

To create the final elcgpur.txt, file query results are called by the access report writer. For each variable or collection of variables a report formats the results of the data queries into the exact FORTRAN fixed format position necessary to be read into the PMM. The most often employed method for this is to have a report with the historical data include a sub-report which appends the STEO year data to it. These individual reports are all then included in the master report "zz- Generate Elcgpur" in the appropriate sequence. This file is then exported from the database as a text file.

Because Access formats reports to a specific printer (page size), additional lines appear where there are breaks in pages. To remove them a Short VBA script was written (eat space) that removes all of the blank lines from the file. All of the report generation and subsequent post-processing can be done automatically by running the macro "Make Elcgpur." The resulting file will be placed in the local c:\ directory of the desktop computer running the macro. Formatting inconsistencies occur when using Access 2002. To avoid the inconsistences, run the report in Access 2000.

H.2 Processing Other Historical Data

In addition to developing an input history file (described in Appendix H-1), the PMM utilizes other historical data to develop some inputs and to support analysis of the model results. This section describes the updating of these data, which is usually done on an annual basis.

Petroleum Product Price Data

Data on petroleum product prices is obtained from the EIA-782 surveys. The EIA-782A survey contains only refiner data, the EIA-782B survey includes petroleum marketers. Prices and volumes are produced monthly for the *Petroleum Marketing Monthly* and updated for annual publication in the *Petroleum Marketing Annual* available in the summer of each year. This information is also available as series of OGIRS keys from which the state level data by product can be retrieved. By matching equivalent product volume and price information for each state a weighted average for each Census District can be determined.

Historical Prices and Margins

Historical wholesale and end-use prices from the EIA-782 are aggregated and presented in tabular form by product type and Census Division. The end-use transportation prices include State and Federal taxes but for jet fuel and LPGs the State taxes are not included prior to 1995.

Differentials with the world oil price (the refiner acquisition cost of imported oil from the EIA-14) are also calculated by product type and Census Division and presented in tabular form for analyzing similar margin calculations from the PMM. The margins include the 1 percent local tax that is currently being added to gasoline price projections.

APPENDIX I

Ethanol Supply Model

Appendix I. Ethanol Supply Model

I.1   Model Purpose

The objective of the ethanol supply model is to provide the NEMS Petroleum Market Model (PMM) with supply curves for corn and cellulose based ethanol, thus allowing the PMM to forecast transportation ethanol demand throughout the NEMS forecast period. To be consistent with the market clearing mechanism adopted for NEMS, the model provides ethanol prices in the form of annual price-quantity curves. The curves, derived from an ethanol production cost function, represent the prices of ethanol at which associated quantities of transportation ethanol are expected to be available for production of E85 and ETBE, and for blending with gasoline.

The delivered ethanol prices are provided to the PMM linear program in the form of a separate supply curve for each of the nine U.S. Census Divisions. The majority of ethanol currently produced in the United States is made from corn and is produced in the East North Central and the West North Central Census Divisions (NEMS regions 3 and 4, respectively). Smaller amounts are available in the South Atlantic, East South Central, West South Central, Mountain, and the Pacific Census Divisions (NEMS regions 5, 6, 7, 8, and 9, respectively). The PMM also models planned cellulose-based ethanol production in all Census Divisions beginning in 2009. Cellulose ethanol is produced from regionally-available agriculture residues, forestry waste, and energy crops such as switchgrass and hybrid poplar.

I.2   Corn-Based Ethanol

Fundamental Assumptions

The cost of corn ethanol is subdivided into capital cost, feedstock cost, operating cost, energy cost, and a credit for marketable coproducts of ethanol production. Energy cost includes the energy needed to grow and transport corn to market and the energy needed to run the ethanol plant. Each of the above factors contributes a part of the total price of ethanol.

Conversion of corn to ethanol is accomplished by either a wet milling or dry milling process. The coproducts produced from the wet milling process are corn gluten feed (CGF), corn gluten meal (CGM), and corn oil, while the dry milling process produces distillers' dried grains with solubles (DDGS). Coproduct credits for wet mills and dry mills are estimated from ethanol industry financial data.

The price of corn is projected from *The U.S. Farm Economic Effects of a 6 Billion Gallon Renewable Fuel Standard, a 8 Billion Gallon Renewable Fuel Standard, and Elimination of the Federal Ethanol Tax Credit*, Department of Agriculture, July 2005. This paper estimates the effect on agricultural markets of expanding

ethanol production by 6 or 8 billion gallons over baseline levels by 2012. For each case, the authors constructed two agricultural market forecasts, one with a baseline level of ethanol production from corn and another with higher levels of ethanol production from corn. The forecasts include corn prices and quantity of corn input to ethanol production for each forecast year. Since PMM models corn ethanol production levels as high as 12 billion gallons, the results of the 8-billion-gallon case are used in PMM. The difference between corn prices and the difference between quantities of corn used for ethanol production gives the rate of change of corn prices with respect to quantity of corn input to ethanol production. The most current baseline corn prices and corn ethanol production were obtained from *USDA Agricultural Baseline Projections to 2014* (http://www.usda.gov/oce/waob/commodity-projections/USDA%20Agricultural%20Baseline%20Projections%20to%202014.pdf) The baseline forecast and the estimated rate of change are used to construct a cost curve of corn to ethanol production.

Energy cost of corn production is estimated from *The Energy Balance of Corn Ethanol: An Update.* Fuel and chemical use per acre of land, fuel use in chemical production, acres planted, and average yields per acre were estimated for nine major corn-producing States. The majority of fuel ethanol is produced in Census Division 4, so estimates for this region were assumed for all other regions. The *USDA Agricultural Baseline Projections to 2014* include energy costs in its corn price estimates. Estimates of delivered industrial energy prices from *Annual Energy Outlook 2005* were deducted in order to estimate the price of corn to ethanol producers excluding the energy needed to grow the corn. The quantities of fuel and current industrial energy prices are used to estimate the energy cost of corn production within NEMS.

Wet milling accounts for about 31 percent of current ethanol production, while new ethanol facilities are projected to be dry milling plants.[1] PMM can choose to produce up to 782 Mbbl/day of corn ethanol in any forecast year. The variability of the market price for the feedstock corn and the conversion by-products and the variable influences of competitive uses for corn (e.g., for producing corn syrup) give rise to broad fluctuations in net corn feedstock prices. As ethanol production from corn increases, land becomes scarcer, causing both land and feedstock costs to increase. These factors are included in the Agriculture model. The Agriculture projections end in 2014, so net feedstock prices for 2015 to 2030 were set equal to the 2014 estimates. The net feedstock costs were then converted to 1987 dollars .

In addition to feedstock prices and quantities, the model requires capital cost, feedstock conversion cost (non-energy operating cost), and energy cost data. The cost data were derived from several sources which are documented in the Inventory of Variables, Data, and Parameters section of this report. Note that with this theoretical approach, only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs, (capital, operating, and process energy) are independent of production quantities.

Capital and conversion costs were assumed to be constant across all Census Divisions and for all forecast

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1 Renewable Fuels Association online ethanol plant list and internet search for wet-mill ethanol producers.

years. Energy costs vary across Census Divisions as a function of industrial-sector coal, natural gas, and electricity prices.   Natural gas prices are obtained from the NEMS Natural Gas Transmission and Distribution Model, coal prices are from the NEMS Coal Market Model, and electricity prices are from the NEMS Electricity Market Model.

There are currently two Federal tax incentives for blending ethanol into gasoline. One is a reduced rate of Federal excise tax on ethanol-blended gasoline, and the other is a business income tax credit for ethanol blended into gasoline. The excise tax reduction and income tax credit are of equal value, 51 cents per gallon of ethanol

Key Computations and Equations

Corn ethanol costs net of energy and subsidies are calculated in a separate spreadsheet (NEMScornsupplycurve.xls, maintained by Tony Radich of EIA). These costs are tabulated as a function of ethanol production quantity in the PMM input file WETOHIN. This file also contains natural gas, coal, and electricity use as a function of ethanol production quantity.   Once the data are read, the ethanol price is calculated from the following equation:

$$WPETOH_{1,cd,t,e} = [\ FC_{t,e} + CAPCST_e + OPCST_e$$
$$+ PEN_{cd,t,e} - (STSUB_{cd} + ETHCRD_t)/ MC\_JPGDP_t]*42$$

where:

$WPETOH_{1,cd,t,e}$ = Delivered price of corn ethanol produced in Census Division cd in year t for volume step e (1987 $/barrel),

$FC_{1,t,,e}$ = Feedstock corn production cost, exclusive of energy, in year t for volume step e (1987 $/gal),

$CAPCST1_e$ = Capital cost for corn conversion technology for volume step e (1987 $/gal),

$OPCST_e$ = Operating costs, exclusive of energy, for volume step e (1987 $/gal),

$PEN_{cd,t,e}$ = Cost of energy used in the corn-to-ethanol conversion process in Census Division cd in year t on volume step e (1987 $/MMBtu),

$STSUB_{cd}$ = State incentive for corn ethanol production in Census Division cd (nominal $/gal).

$ETHCRD_t$ = Federal motor fuels excise tax credit for ethanol production in year t

(nominal \$/gal)

MC_JPGDP_t = GDP chained price index in year t (1987=1)

42 = number of gallons per barrel

Capital cost is calculated as follows:

$$BNDRET1_e = (1 + MC\_RMCORPBAA_e/100 + BNDPREM1_e/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$BNDCRF1_e = BNDRET1_e/(1 - 1/(1 + BNDRET1_e)**CRNLIFE_e)$$

$$EQRET1_e = (1 + MC\_RMTCM10Y_e/100 + BETA1_e*EQPREM1_e/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$EQCRF1_e = EQRET1_e/(1 - 1/(1 + EQRET1_e)**CRNLIFE_e)$$

$$CAPCST_e = (BNDCRF_e*CRNDEBT_e/100 + EQCRF_e*(100 - CRNDEBT_e)/100)*CRNCAP_e$$

where:

$BNDRET1_e$	=	*Real return on debt required for corn ethanol plants on volume step e*
$MC\_RMCORPBAA_t$	=	*Nominal yield of BAA-rated corporate bonds in year t*
$BNDPREM1_e$	=	*Bond premium required for corn ethanol plants on volume step e*
$BNDCRF1_e$	=	*Bond capital recovery factor on volume step e*
$CRNLIFE_e$	=	*Economic life of ethanol plants on volume step e*
$EQRET1_e$	=	*Real return on equity required for corn ethanol plants on volume step e*
$MC\_RMTCM10Y_t$	=	*Nominal yield on 10-year treasury note in year t*
$BETA1_e$	=	*Multiplier applied to equity risk premium on volume step e*
$EQPREM1_e$	=	*Market risk premium for equity on volume step e*
$EQCRF1_e$	=	*Equity capital reconvery factor on volume step e*
$CRNDEBT_e$	=	*Debt fraction of corn ethanol plant finance on volume step e*
$CRNCAP_e$	=	*Capital cost per annual gallon of capacity for corn ethanol plant on volume step e*

The price of energy in each case is calculated as follows:

$$PEN_{cd,t,e} = CRNDS* PDSIN_{cd,t} + CRNMG* PMGIN_{cd,t} + CRNLG* PLGIN_{cd,t}$$
$$+(CRNNG+QNG_{t,e})*PNGIN_{cd,t} + QCL_{t,e}*PCLIN_{cd,t}+(CRNEL+QEL_{t,e})* PELIN_{cd,t}$$

where:

$CRNDS$	=	Distillate needed to grow corn (MMBtu/gal)
$CRNMG$	=	Motor gasoline needed to grow corn (MMBtu/gal)
$CRNLG$	=	Liquefied petroleum gas (LPG) needed to grow corn (MMBtu/gal)
$CRNEL$	=	Electricity needed to grow corn (MMBtu/gal)
$CRNNG$	=	Natural gas needed to grow corn (MMBtu/gal)
$PDSIN_{cd,t}$	=	Industrial price of distillate for Census Division cd in year t ($/MMBtu)
$PMGIN_{cd,t}$	=	Industrial price of motor gasoline for Census Division cd in year t ($/MMBtu)
$PLGIN_{cd,t}$	=	Industrial price of LPG for Census Division cd in year t ($/MMBtu)
$PNGIN_{cd,t}$	=	Industrial price of natural gas for Census Division cd in year t ($/MMBtu),
$PCLIN_{cd,t}$	=	Industrial price of coal for Census Division cd in year t ($/MMBtu).
$PELIN_{cd,t}$	=	Industrial price of electricity for Census Division cd in year t ($/MMBtu).
$QNG_{t,e}$	=	Quantity of natural gas in year t on volume step e, MMBtu/gal
$QCL_{t,e}$	=	Quantity of coal in year t on volume step e, MMBtu/gal
$QEL_{t,e}$	=	Quantity of electricity in year t on volume step e, MMBtu/gal

Inventory of Variables, Data, and Parameters

MODEL INPUT: $MC\_RMCORPBAA_t$, $MC\_RMTCM10Y_t$

DEFINITION: Nominal yields of BAA-rated corporate bonds and 10-year treasury notes, respectively, in year t

SOURCE: Generated by the Macroeconomic Model. Located in Macroecnomic common block MACOUT.

MODEL INPUT: MC_JPGDP_t

DEFINITION: GDP chained price index in year t. 1987=1.

SOURCE: Generated by the Macroeconomic Model. Located in Macroecnomic common block MACOUT.

MODEL INPUT: $CRNLIFE_e$

DEFINITION: Capital recovery period for corn ethanol plants on volume step e. Value is 10 years.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls, by Thomas Lee of OIAF.

MODEL INPUT: $BNDPREM1_e$

DEFINITION: Bond premium required for corn ethanol plants on volume step e. Value is 0.25 percent for all steps.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $EQPREM1_e$

DEFINITION: Market risk premium for equity investment. Value is 6.75 percent for all equity investments.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $BETA1_e$

DEFINITION: Corn ethanol-specific multiplier applied to equity risk premium on volume step e. Value is 1.5 for dry mills.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $CRNDEBT_e$

DEFINITION: Debt fraction of corn ethanol plant finance on volume step e. Value is 40 percent for all steps.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $CRNCAP_e$

DEFINITION: Capital cost per annual gallon of capacity for corn ethanol plant on volume step e. Value is 0 for existing plants and $0.885 (1987 $) for dry mills that are not yet built.

SOURCE: Conversation with John Urbanchuk of LECG Consultants, July 19, 2005.

MODEL INPUT: $OPCST_e$

DEFINITION: Operating cost, exclusive of energy, for corn ethanol plants on volume step e.

Value is $0.261/gallon for wet mills and $0.167/gallon for dry mills (1987 $) for 2000 thru 2030. Located in the spreadsheet NEMScornsupplycurve.xls.

SOURCE: *USDA's 2002 Ethanol Cost-of-Production Survey*, Agricultural Economic Report Number 841

MODEL INPUTS: *CRNDS, CRNMG, CRNLG, CRNEL, CRNNG*

DEFINITION: Distillate, motor gasoline, LPG, electricity, and natural gas, respectively , needed to grow corn.

SOURCE: Shapouri, Hosein; Duffield, James A.; Wang, Michael. *The Energy Balance of Corn Ethanol: An Update*. Agricultural Eocnomic Report Number 814.

MODEL INPUT: $PDSIN_{cd,t}$, $PMGIN_{cd,t}$, $PLGIN_{cd,t}$

DEFINITION: Prices of distillate, motor gasoline, and LPG, respectively, for industrial use in Census Division cd in year t.

SOURCE: Generated by the Petroleum Market Model. Located in the Price common block MPBLK.

MODEL INPUT: $PCLIN_{cd,t}$

DEFINITION: Price of coal for industrial use in Census Division cd in year t.

SOURCE: Generated by the Coal Market Model. Located in the Price common block MPBLK.

MODEL INPUT: $PNGIN_{cd,t}$

DEFINITION: Price of natural gas for industrial use in Census Division cd in year t.

SOURCE: Generated by the Natural Gas Transmission and Distribution Model. Located in the Price

common block MPBLK.

MODEL INPUT: $PELIN_{cd,t}$

DEFINITION: Price of electricity for industrial use in Census Division *cd* in year *t*.

SOURCE: Generated by the Electricity Market Model. Located in the Price common block MPBLK.

MODEL INPUT: $QNG_{t,e}$, $QCL_{t,e}$; *e*=1

DEFINITION: Quantity of natural gas and coal needed to convert corn to ethanol in year *t* on volume step 1.

Ethanol production on this step is assumed to come from wet mills, which consume 0.051 million Btu of process energy and electricity per gallon of output. Wet mills generate their own electricity, so their only energy inputs are coal and natural gas. Natural gas is 20% of the energy input per gallon, and coal is 80% of the energy input per gallon.

SOURCE: *USDA's 1998 Ethanol Cost-of-Production Survey*, Agricultural Economic Report Number 808

MODEL INPUT: $QNG_{t,e}$, $QCL_{t,e}$; *e*=2-4

DEFINITION: Quantities of natural gas and coal needed to convert corn to ethanol in year *t* on volume steps 2-4.

Ethanol production on these steps is assumed to come from dry mills. Process energy consumption values, in million Btu per gallon, are as follows: 0.050 in 1990, 0.041 in 2000, 0.037 in 2005, 0.035 in 2020 and 2025. This decreasing trend is based on the assumption that energy required decreases linearly over time. Existing dry mills, on step 2, use natural gas for 50% of their process energy and coal for 50% of their process energy. New dry mills, on steps 3 and 4, use natural gas for 100% of their process energy. Located in the spreadsheet NEMScornsupplycurve.xls.

SOURCE: Marland, G. and A.F. Turhollow. 1991. "CO_2 Emissions From the Production and Combustion of Fuel Ethanol from Corn." *Energy*, 16(11/12):1307-1316.

MODEL INPUT: $QEL_{t,e}$; *e*=2-4

DEFINITION: Quantity of electricity needed to convert corn to ethanol in year t on volume steps 2-4.

Ethanol production on these steps is assumed to come from dry mills, which consume 1.1 kwh (0.0037 million Btu) per gallon. Located in the spreadsheet NEMScornsupplycurve.xls.

SOURCE: *USDA's 1998 Ethanol Cost-of-Production Survey*, Agricultural Economic Report Number 808

MODEL INPUT: *ETHCRD$_t$*

DEFINITION: Value of Federal tax incentive in year t, in nominal dollars. The incentive is 52 cents per gallon in 2004 and 51 cents per gallon thereafter.

Located in the WETOHIN data input file.

I.3 Cellulose-Based Ethanol

Theoretical Approach

The cost of cellulose ethanol is subdivided into capital cost, feedstock cost, operating cost, and a credit for excess electricity generated at the ethanol plant. As with the corn model, each of the above factors contributes a part of the total price of ethanol.

Biomass feedstock supply is not modeled in the Petroleum Market Model ethanol model. Biomass price/quantity data are obtained from the Renewable Fuels Model of NEMS and are used as input to the ethanol model. The Model Documentation: Renewable Fuels Module of the National Energy Modeling System", DOE/EIA-M069(2005) contains a complete description of the approach and assumptions used in generating the biomass feedstock supply functions.

Briefly, the biomass use in NEMS is modeled as two distinct markets, the captive and non-captive biomass markets. The captive market pertains to users with dedicated biomass supplies that obtain energy by burning biomass byproducts resulting from the manufacturing process. The noncaptive market is defined to include the commercial, transportation, and electric utility sectors, as well as the resources marketed in the industrial sector. There is an additional noncaptive market serving residential uses of biomass.

EIA developed a fairly simple model structure consisting of one supply schedule per region. This schedule defines the quantity and cost relationships of biomass resources accessible by all noncaptive, non-residential consumers. It is based on an aggregation of supply/price information from U.S. Forest Service and forest product experts. The wood portion of the cost-supply schedule is static throughout the model period. Energy crop cost-supply schedules are also developed and superimposed onto the wood total.

Fundamental Assumptions

A basic assumption for the biomass feedstock is that the supply price for noncaptive biomass energy is the same across all sectors. Biomass feedstock costs are input from the NEMS Renewable Fuels Model at the Census Division level. Biomass usage by the PMM ethanol model is fed back to the Renewable Fuels Model. At lower prices, the NEMS biomass supply is mostly urban wood waste. Cellulose ethanol technology, however, is being developed for agricultural residue, forestry residue, and purpose-grown energy crops. These sources of supply are assumed to be available only at higher biomass prices. A feedstock cost premium, estimated by region and by ethanol quantity, was applied to cellulose ethanol to reflect this.

An important modeling consideration for cellulose ethanol production is the imposition of a constraint on the amount of ethanol production capacity assumed for the early years of the forecast. Ethanol from cellulose is relatively new technology and ethanol production from cellulose is currently at the demonstration level. By assumption, commercial cellulose ethanol production begins in 2010 in the *AEO2005* reference case. Commercial production is assumed to begin 2 years earlier in the *AEO2005* High Renewables side case. A constraint on cellulose ethanol production prevents unrealistically large increases in production capacity from occurring suddenly in response to favorable market prices. Cellulose ethanol production capacity is allowed to grow by 50 million gallons per year per region after 2010 (2008 in the High Renewables case)...

In addition to feedstock prices and quantities input from the Renewable Fuels Model, the ethanol model requires feedstock conversion and energy cost data, and capital and operating cost data. The conversion and capital cost data were derived from a joint study by the Dept. of Agriculture and the Dept. of Energy, *Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks.*,

Ethanol production costs are assumed to be constant across the United States. However, feedstock availability and price varies from Census Division to Census Division. Ethanol production in Census Divisions 2 and 7 is expected to be based on forest residue. Census Divisions 3 and 4 have corn stover in large volume. The feedstocks available in Census Division 9 are forest residue and rice straw The Federal tax incentives for blending ethanol also apply to ethanol from cellulose.

Key Computations and Equations

The main computations performed by the cellulose portion of the ethanol model involve the derivation of an ethanol supply-price curve for each Census Division. The computations consist of three major steps:

1. Reading in ethanol component cost data from the PMM input file WETOHIN.
2. Obtaining biomass feedstock prices at the census division level from the Renewable Fuels Model.
3. Derivation of delivered ethanol prices, calculated as a function of the biomass feedstock price and the ethanol conversion costs.

The delivered ethanol price equation is as follows:

$$WPETOH_{2,cd,t,e} = [CAPCST2_e + FC_{2,t,,e} + OPCSTCL_e - PWRCDCL_e - ETHCRD_t/ MC\_JPGDP_t]*42$$

where:

$WPETOH_{2,cd,t,e}$ = Delivered price of cellulose ethanol in Census Division *cd* in year *t* for volume step *e* (1987 $/barrel)

$CAPCST2_e$ = Capital cost for cellulose conversion technology for volume step *e* (1987 $/gal)

$FC_{2,t,e}$ = Cellulose feedstock cost, exclusive of energy, in year t for volume step e (1987 \$/gal),

$OPCSTCL_e$ = Operating cost for volume step e (1987 \$/gal),

$PWRCDCL_e$ = Power credit for co-products combusted and sold as power for volume step e

$ETHCRD_t$ = Federal motor fuels excise tax credit for ethanol production in year t (nominal \$/gal)

MC_JPGDP_t = GDP chained price index in year t (1987=1)

42 = number of gallons per barrel

Capital cost is calculated as follows:

$$BNDRET2_e = (1 + MC\_RMCORPBAA_t/100 + BNDPREM2_e/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$BNDCRF2_e = BNDRET2_e/(1 - 1/(1 + BNDRET2_e)^{**}CLLLIFE_e)$$

$$EQRET2_e = (1 + MC\_RMTCM10Y_t/100 + BETA2_e*EQPREM2_e/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$EQCRF2_e = EQRET2_e/(1 - 1/(1 + EQRET2_e)^{**}CLLLIFE_e)$$

$$CAPCST2_e = (BNDCRF2_e*CLLDEBT_e/100 + EQCRF2_e*(100 - CLLDEBT_e)/100)*CLLCAP_e$$

where:

$BNDRET2_e$ = *Real return on debt required for cellulose ethanol plants on volume step e*
$MC\_RMCORPBAA_t$ = *Nominal yield of BAA-rated corporate bonds in year t*
$BNDPREM2_e$ = *Bond premium required for cellulose ethanol plants on volume step e*
MC_JPGDP_t = *GDP chained price index in year t*
$BNDCRF2_e$ = *Bond capital recovery factor on volume step e*
$CLLLIFE_e$ = *Capital recovery period for cellulose ethanol plants on volume step e*
$EQRET2_e$ = *Real return on equity required for corn ethanol plants on volume step e*
$MC\_RMTCM10Y_t$ = *Nominal yield on 10-year treasury note in year t*
$BETA2_e$ = *Cellulose ethanol specific multiplier applied to equity risk premium on volume step e*
$EQPREM2_e$ = *Market risk premium for equity on volume step e*
$EQCRF2_e$ = *Equity capital recovery factor on volume step e*

| $CLLDEBT_e$ | = | Debt fraction of cellulose ethanol plant finance on volume step e |
| $CLLCAP_e$ | = | Capital cost per annual gallon of capacity for cellulose ethanol plant on volume step e |

Feedstock cost is evaluated as follows:

If $PBMET_{cd,t}<=1.601$ then $FC_{2,t,e}=1.601*17.2/CONEFF_t$
If $PBMET_{cd,t}<=1.689$ then $FC_{2,t,e}=1.689*17.2/CONEFF_t$
If $PBMET_{cd,t}<=1.93$ then $FC_{2,t,e}=1.93*17.2/CONEFF_t$
If $PBMET_{cd,t}<=2.758$ then $FC_{2,t,e}=2.758*17.2/CONEFF_t$

Where

$PBMET_{cd,t}$	=	Biomass feedstock cost for Census Division cd in year t (1987 \$/MMBtu)
17.2	=	MMBtu of biomass per short ton of biomass.
$CONEFF_t$	=	Feedstock conversion rate, gallons of ethanol per ton of biomass. Yield increases from 79.8 gallons per ton of feedstock in 2010 to 85 gallons per ton in 2014.

Inventory of Variables, Data, and Parameters

MODEL INPUT: $MC\_RMCORPBAA_t$, $MC\_RMTCM10Y_t$

DEFINITION: Nominal yields of BAA-rated corporate bonds and 10-year treasury notes, respectively, in year t

SOURCE: Generated by the Macroeconomic Model. Located in Macroecnomic common block MACOUT.

MODEL INPUT: MC_JPGDP_t

DEFINITION: GDP chained price index in year t. 1987=1.

SOURCE: Generated by the Macroeconomic Model. Located in Macroecnomic common block MACOUT.

MODEL INPUT: $CLLLIFE_e$

DEFINITION: Capital recovery period for cellulose ethanol plants on volume step e. Value is 20 years.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls, by Thomas Lee of OIAF.

MODEL INPUT: $BNDPREM2_e$

DEFINITION: Bond premium required for corn ethanol plants on volume step e. Value is 0.5 percent for all steps.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $EQPREM2_e$

DEFINITION: Market risk premium for equity investment. Value is 6.75 percent for all equity investments.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $BETA2_e$

DEFINITION: Cellulose ethanol-specific multiplier applied to equity risk premium on volume step e. Value is 1.75.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $CLLDEBT_e$

DEFINITION: Debt fraction of cellulose ethanol plant finance on volume step e. Value is 20 percent for all steps.

SOURCE: Spreadsheet AEO2006 Final Discount Rates.xls.

MODEL INPUT: $CLLCAP_e$

DEFINITION: Capital cost per annual gallon of capacity for cellulose ethanol plant on volume step e. Value is $5.02/gal (1987 $) for all plants.

MODEL INPUT: $FC_{2,t,,e}$

DEFINITION: Cellulose feedstock cost in year t for volume step e (1987 $/gal). The prices for biomass were

chosen to reflect adequate supplies of higher-quality biomass for the step quantity of cellulose ethanol. Cellulose ethanol plants are assumed to use forest wastes, crop residues, and energy crops. It is assumed that they will not use urban wood waste, because its quality is too variable.

MODEL INPUT: $OPCSTCL_e$, $PWRCDCL_e$

DEFINITION: $OPCSTCL_e$ is \$0.428 per gallon, and $PWRCDCL_e$ is \$-0.082 per gallon (1987 \$).

SOURCE: McAloon, Andrew; Taylor, Frank; Yee, Winnie. *Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks.* National Renewable Energy Laboratory, October 2000. Located in the WETOHIN input data file.

MODEL INPUT: $PBMET_{cd,t}$

DEFINITION: Biomass feedstock cost for Census Division *cd* in year *t*.

Input from the Renewable Fuels Model.

SOURCE: National Energy Modeling System common block WRENEW.

MODEL INPUT: $ETHCRD_t$

DEFINITION: Value of Federal tax incentive in year *t*, in nominal dollars. The incentive is 52 cents per gallon in 2004 and 51 cents per gallon thereafter.

Located in the WETOHIN data input file.

I.4   Ethanol Transportation Costs

The most comprehensive work regarding ethanol distribution infrastructure and costs is a report by Downstream Alternatives, Inc. (DAI), *Infrastructure Requirements for an Expanded Ethanol Industry,* June 2002, performed for the Department of Energy Office of Energy Efficiency and Renewable Energy. This source was used to develop cost estimates for transporting ethanol between and within Census Divisions (CD's).

The DAI study estimates the infrastructure investment costs and the transportation costs that would likely be incurred if ethanol demand reached 5.0 billion gallons per year (BGY) by 2012. The infrastructure costs are incremental and represent additional expenditures from an established baseline level of 1.5 BGY. Transportation costs are the largest category of costs, far larger than the amortized costs of modifications to petroleum terminals and retail stations for blends of 10 percent ethanol or less. Rail and water are the modes of ethanol transport that are considered, as pipeline shipment is not currently considered a cost-effective method of transport due to special handling requirements of ethanol.

The DAI study examines the costs and ethanol demand by PADD. The links needed for PMM, as shown in Table I1, are based on Census Divisions for demands. There are some discrepancies between the PADD and CD mapping in terms of states; however, for the purpose of ethanol transportation cost estimates between the CD's, the following table is not expected to introduce significant error to the modeling results.

Table I1. DAI Regions and NEMS Regions

DAI Regions		NEMS/PMM Regions	
Code	Locations	Code	Locations
1	PADD 1	1, 2, 5	CDs 1, 2, and 5
2	PADD 2	3, 4	CDs 3 and 4
3	PADD 3	6, 7	CDs 6 and 7
4	PADD 4	8	CD 8
5	PADD 5	9	CD 9

Most ethanol is produced in either CD 3 or 4, and transported by rail, barge, ship, or truck. Ethanol produced and consumed in the same CD is assumed to be shipped by truck at a freight cost of 4 cents/gallon. Starting with the baseline of existing ethanol sales from year 2000, the DAI study examines the costs and ethanol demand for the years 2004, 2007, and 2012. The corresponding demands in the PMM model for each mode of transportation and the estimated freight costs are shown for these 3 years in Tables I2, I3, and I4.

The average cents per gallon in Tables I2 through I4 are provided on an amortized, cost per gallon of ethanol basis. Costs for capital improvement are included in the PMM model but are not included in the freight costs shown below. (Amortized capital improvement costs range from 0.52 cents per gallon to 0.87 cents per gallon, with a nationwide average of 0.66 cents per gallon)

Table I2. 2004 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	44.8	9.0
CD 3	CD 1	Ship	25.1	11.0
CD 3	CD 2	Rail	160.5	8.0
CD 3	CD 2	Ship	89.9	11.0
CD 3	CD 3	Barge	103.2	4.0
CD 3	CD 5	Rail	44.7	8.0
CD 3	CD 5	Ship	25.0	11.0
CD 4	CD 3	Rail	52.0	4.0
CD 4	CD 3	Truck	52.0	4.0
CD 4	CD 4	Truck	103.3	4.0
CD 4	CD 9	Rail	84.0	13.0
CD 4	CD 9	Ship	70.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds, August 2002

Note: Costs shown reflect 2000 dollars.

Table I3. 2007 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	34.8	9.0
CD 3	CD 1	Ship	18.8	11.0
CD 3	CD 2	Rail	124.5	9.0
CD 3	CD 2	Ship	67.4	11.0
CD 3	CD 3	Truck	38.6	4.0
CD 3	CD 5	Rail	34.7	9.0
CD 3	CD 5	Ship	18.8	11.0
CD 3	CD 6	Barge	12.2	3.5
CD 3	CD 6	Rail	24.9	7.0
CD 4	CD 3	Truck	38.6	4.0
CD 4	CD 4	Truck	38.6	4.0
CD 4	CD 6	Barge	4.1	3.5
CD 4	CD 6	Rail	8.3	7.0
CD 4	CD 7	Barge	43.7	3.5
CD 4	CD 7	Rail	88.8	7.0
CD 4	CD 9	Rail	195.0	13.0
CD 4	CD 9	Ship	105.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds, August 2002

Table I4. 2012 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	71.8	9.0
CD 3	CD 1	Ship	43.1	11.0
CD 3	CD 2	Rail	256.8	9.0
CD 3	CD 2	Ship	154.1	11.0
CD 3	CD 3	Barge	16.8	4.0
CD 3	CD 3	Truck	146.3	4.0
CD 3	CD 3	Rail	10.0	4.0
CD 3	CD 5	Rail	71.5	9.0
CD 3	CD 5	Ship	42.9	11.0
CD 3	CD 6	Barge	20.6	3.5
CD 3	CD 6	Rail	11.4	7.0
CD 3	CD 9	Rail	25.0	14.0
CD 3	CD 9	Ship	15.0	14.0
CD 4	CD 1	Rail	17.9	11.0
CD 4	CD 1	Ship	10.8	12.0
CD 4	CD 2	Rail	64.2	11.0
CD 4	CD 2	Ship	38.5	12.0
CD 4	CD 3	Barge	33.6	4.0
CD 4	CD 3	Rail	20.0	4.0
CD 4	CD 3	Truck	36.6	4.0
CD 4	CD 4	Truck	36.6	4.0
CD 4	CD 5	Rail	17.9	11.0
CD 4	CD 5	Ship	10.7	12.0
CD 4	CD 6	Barge	20.6	3.5
CD 4	CD 6	Rail	11.4	7.0
CD 4	CD 7	Barge	110.1	3.5
CD 4	CD 7	Rail	61.0	7.0
CD 4	CD 8	Rail	35.0	4.5
CD 4	CD 9	Rail	225.0	13.0
CD 4	CD 9	Ship	135.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds, August 2002

APPENDIX J

Biodiesel Supply Model

Appendix J. Biodiesel Supply Model

J.1   Model Purpose

The objective of the biodiesel supply model is to provide the NEMS Petroleum Market Model (PMM) with supply curves for biodiesel made from soybean oil and yellow grease. The model provides plant-gate biodiesel prices as a function of quantity for each Census Division and each forecast year. The curves, derived from a biodiesel production cost function, represent the prices at which biodiesel is expected to be available for blending into distillate and highway diesel.

J. 2   Fundamental Assumptions

PMM can choose up to approximately 200 million gallons of biodiesel from soybean oil and up to approximately 270 million gallons of biodiesel from yellow grease. Yellow grease consists primarily of used cooking oil from restaurants. As such, its availability is nationwide and is assumed to grow at the same rate that population grows. Biodiesel production capacity by feedstock is allocated among Census Divisions in PMM according to the National Biodiesel Board's map of existing and potential producers.[1]

The biodiesel model uses a process costing approach to model the impacts of net feedstock production costs plus capital and operating costs. Biodiesel is produced in a type of chemical reaction called a transesterification. Fats or oils are reacted with an alcohol, usually methanol, to produce esters of the fat or oil and glycerine.

The price of soybean oil is projected from *Effects on the Farm Economy of a Renewable Fuels Standard for Motor Vehicle Fuel*, Office of Energy Policy and New Uses, Department of Agriculture, August 2002. This paper estimates the effect on agricultural markets of a renewable fuels requirement for gasoline and diesel fuel. The Department of Agriculture constructed two agricultural market forecasts, a renewable fuels standard case with and a reference case without biodiesel production from soybean oil. The forecasts include soybean oil prices and quantity of oil input to biodiesel production for each forecast year. The quotient of the increase in soybean oil prices and the quantity of soybean oil used for biodiesel production in the renewable fuels standard case gives the rate of change of soybean oil prices with respect to quantity of soybean oil input to biodiesel production. The most current baseline soybean oil prices, assuming no biodiesel production, were obtained from *USDA Agricultural Baseline Projections to 2014* (http://www.usda.gov/oce/waob/commodity-projections/USDA%20Agricultural%20Baseline%20Projections%20to%202014.pdf) The baseline forcast and the estimated rate of change are used to construct a cost curve of soybean oil to biodiesel production.

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1 http://www.biodiesel.org/buyingbiodiesel/producers_marketers/ProducersMap-existingandpotential.pdf. The April 2005 version was used for AEO2006. Producer capacities were determined by a Google search on each producer name.

The Department of Agriculture does not forecast yellow grease prices. In the past, however, the prices of yellow grease and soybean oil have moved together. Monthly soybean oil price data were obtained from the Department of Agriculture, and monthly yellow grease price data were obtained from the Jacobsen Publishing Company. Unweighted averages were used to construct annual prices. The Producer Price Index was used to covert all prices to a 2001 basis. A linear regression gives:

Yellow grease price = 0.49 *Soybean oil price*

where prices are in 2001 dollars per pound. Baseline yellow grease prices are obtained by substituting baseline soybean oil prices into the above equation. It follows from the regression equation that:

Δ*Yellow grease price* = 0.49 Δ*Soybean oil price*,

The rate of increase in soybean oil prices with respect to soybean oil input to biodiesel production is substituted into this relation to obtain the rate of increase in yellow grease prices with respect to yellow grease input to biodiesel production. The baseline forcast and the estimated rate of change are used to construct a cost curve of yellow grease to biodiesel production.

The feedstock cost credit for the glycerine coproduct is estimated to be 11 cents per gallon (1987 dollars; E-mail from K. Shaine Tyson of the National Renewable Energy Laboratory, Feb. 12, 2002).

In addition to feedstock prices and quantities, the model requires capital cost and operating cost. The cost data are documented in the Inventory of Variables, Data, and Parameters section of this report. Note that with this theoretical approach, only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs are independent of production quantities.

The American Jobs Creation Act of 2004 enacted exemptions from Federal motor fuels taxes for biodiesel that are identical in structure to the exemption for ethanol. The credits are $1 per gallon of biodiesel from agricultural commodities such as soybean oil and 50 cents per gallon of biodiesel from recycled oils such as yellow grease. The Energy Policy Act of 2005 extends these credits through 2008.

J. 3   Key Computations and Equations

Biodiesel costs including subsidies are calculated in a separate spreadsheet (NEMSbiodieselsupplycurve.xls, maintained by Tony Radich of EIA). These costs are tabulated as functions of biodiesel production quantity. The prices for biodiesel are calculated from the following equations:

$$WPBDSL_{1,cd,t,e} = [FC_{1,t,e} + CAPBDSL + OPBDSL - WTP_{i,t} - FEDSUBV_t / MC\_JPGDP_t]*42$$

$$WPBDSL_{2,cd,t,e} = [FC_{2,t,e} + CAPBDSL + OPBDSL - WTP_{i,t} - FEDSUBNV_t / MC\_JPGDP_t]*42$$

Where:

i=feedstock index; 1≡soybean oil biodiesel, 2≡yellow grease biodiesel

$PBDSL_{i,cd,t,e}$= Delivered price of biodiesel produced from feedstock i in Census Division cd in year t for volume step e (1987 $/barrel),

$FC_{i,t,e}$= Net cost of feedstock i in year t for volume step e (1987 $/gal),

$CAPBDSL$ =Capital cost for conversion technology (1987 $/gal),

$OPBDSL$=Operating cost for biodiesel production (1987 $/gal),

$WTP_{i,t}$=Premium that diesel users are willing to pay for biodiesel from feedstock i in year t (2004 $/gal).

$FEDSUBV_t$=Federal excise tax exemption for biodiesel from soybean oil in year t (nominal $/gal).

$FEDSUBNV_t$=Federal excise tax exemption for biodiesel from yellow grease in year t (nominal $/gal).

MC_JPGDP_t=GDP chained price index in year t (1987=1)

42=number of gallons per barrel

J. 4. Inventory of Variables, Data, and Parameters

MODEL INPUT: *CAPBDSL*

DEFINITION: Capital cost of biodiesel plants.

A new biodiesel plant costs $0.729 per gallon per year of capacity (1987 $), discounted at 10 percent over 15 years. Value is $0.096 per gallon (1987 $) Located in spreadsheet NEMSbiodieselsupplycurve.xls.

SOURCE: National Renewable Energy Laboratory estimate

MODEL INPUT: *OPBDSL*

DEFINITION: Operating cost of biodiesel plants, including energy

Value is $0.308 per gallon (1987 $). Located in spreadsheet NEMSbiodieselsupplycurve.xls.

SOURCE: National Renewable Energy Laboratory estimate

MODEL INPUT: $WTP_{i,t}$

DEFINITION: Premium that diesel users are willing to pay for biodiesel.

Values are $1 per gallon of soybean biodiesel and 50 cents per gallon of yellow grease biodiesel after 2008 (2004 $). Located in spreadsheet NEMSbiodieselsupplycurve.xls.

MODEL INPUT: $FEDSUBV_t$

DEFINITION: Value of Federal tax incentive for virgin oil (e.g. soybean oil) biodiesel in year t .

Value is $1.00 per gallon (nominal $) through 2008 and zero thereafter. Located in the WETOHIN data input file.

MODEL INPUT: $FEDSUBNV_t$

DEFINITION: Value of Federal tax incentive for nonvirgin oil (e.g. yellow grease) biodiesel in year t.

Value is 50 cents per gallon (nominal cents) through 2008 and zero thereafter. Located in the WETOHIN data input file.

MODEL INPUT: MC_JPGDP_t

DEFINITION: GDP chained price index in year t. 1987=1.

SOURCE: Generated by the Macroeconomic Model. Located in Macroecnomic common block MACOUT.