# Regional Short-Term Energy Model (RSTEM) Overview

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## 1. Background

The Energy Information Administration's (EIA) Office of Energy Markets and End Use (EMEU) is responsible for producing the monthly Short-Term Energy Outlook (STEO), which forecasts U.S. supplies, demands, imports, stocks, and prices of various forms of energy.  In addition to the STEO, EIA also produces a [Summer Motor Gasoline Outlook](#) (in April) and a [Winter Fuels Outlook](#) (in October) as part of the short-term forecasting program.  A data query system is also available to search of data series.  Backing up the forecasting system is EIA's extensive energy data collection and publication process.

STEO uses the Short-Term Integrated Forecasting (STIFS) model, which is an integrated information system, bringing together energy quantities and prices from various sources within EIA (and from elsewhere) in a consistent, time series format. This energy information is coupled with other economic and non-economic information to form a modeling database from which forecasting equations are estimated, saved and later used to produce monthly projections and reports.  Other models that run outside the STIFS system are needed to generate some forecast information, such as the macroeconomic forecasts.

STIFS consists of over 300 equations (excluding equations used to convert standard units into energy equivalents such as British thermal units (Btu's)), of which just over 100 are estimated. The estimated regression equations form a system of interrelated forecasting equations. The selection of functional form and the estimation technique is generally done on an equation-by-equation basis. The general method of estimation is ordinary least squares.  Some equations incorporate a correction for autocorrelation of the error term.  STIFS model [documentation](#) is available on the STEO Website.

The STIFS model is almost entirely framed as a national-level model.  While this feature is adequate for portraying some of the more important near-term developments in major fuel markets, it is limited in its ability to provide regional forecasts, which are of particular interest to EIA customers.  Consequently, EIA expanded the STIFS model to include selected regional forecasts to provide greater geographic detail to the national forecasts. The regional model allows for unique regional factors that affect energy demands, supplies, and prices to be explicitly modeled: these factors are obscured in an aggregated, national-level model.  The new model, the Regional Short-Term Energy Model (RSTEM), makes use of some of the structure contained in STIFS, but is more complex due to the new regional detail.

One of the goals of the regionalization project is to provide a national forecast while providing regional detail.  The most detailed regional forecasts are in the natural gas and electricity markets, partly because these markets tend to have strong regional differences and have available regional data.  However, considerable effort has been made to provide regional forecasts for key petroleum products, as well. The only

regional consideration for coal demand is for the demand from the electric power sector, although that is the bulk of the market.  The same is true for renewables.

The Regional Short-Term Energy Model (RSTEM) utilizes estimated econometric relationships for demand, inventories and prices to forecast energy market outcomes across key sectors and selected regions throughout the United States.  The structure of the model is sufficiently detailed to allow for a richer and deeper treatment of the key trends and forces in major domestic energy markets than was possible under STIFS.  The frequency of the model database remains monthly, and the forecast horizon remains at 12 to 24 months ahead.  Due to the limitations of data availability at this frequency, the economic sectors covered for the energy demands and end-use prices are somewhat limited.

Table 1 provides a summary of the coverage, by major fuel category, of the concepts in RSTEM.

### Table 1.  STEM Model Regionalization Scheme

| | Regions | Comments |
|---|---|---|
| **Regionalized Components** | | |
| **Macroeconomic/Weather/Household** | | |
| **Macro Data/Projections** | 9 Census Divisions | GI quarterly regional macro model/U.S. bridge |
| **Household Characteristics** | 9 Census Divisions | RECS/Census/NEMS and interpolations |
| **Weather** | 9 Census Divisions | CPC/NOAA |
| **Electricity Demand (Retail Sales)** | 9 Census Divisions + NY, FLA, CA, TX and AK+HI | Based on EIA state-level sales and revenue |
| **Electricity Supply** | 9 Census Regions + NY, FLA, CA, TX and AK+HI | Generation and fuel consumption patterns will be modeled for all Census Divisions, except that NY, FLA, TX and CA will be treated separately from the rest of their respective Census Divisions. Electricity imports will be determined first at the national level, then estimates shared to the supply regions |
| **Natural Gas Demand** | 9 Census Divisions | Based on EIA state-level sales and revenue |
| **Natural Gas Supply** | National/Regional Hybrid | National-level mechanism for benchmark gas commodity price, selected regions for basis differential calculations.  End-use prices (including power sector prices) will be at the Census Division or power supply region level.   Storage will be handled at |

| | | |
|---|---|---|
| | | the AGA regional level. |
| **Coal Supply** | 3 Production Regions (Eastern, Interior, and Western) | Provided Exogenously to RSTEM by EIA's Office Coal, nuclear, Electric and Alternate Fuels. Selected sub-regions possible. |
| **Petroleum Prices/Inventories** | 5 PADD Regions | Gasoline, heating oil and propane. Based on EIA'S PSM, PMM, and price survey data and commercial information on spot prices |
| **National Components**<br>  **Gasoline/Hwy Travel Demand**<br>  **Jet Fuel Supply/Demand**<br>  **Non-power Distillate Fuel Demand/Supply**<br>  **Non-power Residual Fuel Demand/Supply**<br>  **LPG Supply/Demand Balance**<br>  **Other Petroleum Products Supply/Demand**<br>  **Crude Oil Supply/Demand**<br>  **Petroleum Products Import**<br>  **Non-power Coal Demand**<br>  **Non-retail Electricity Demand**<br>  **Electricity Imports**<br>  **Electricity Exports**<br>  **Natural Gas Imports**<br>  **Natural Gas Exports**<br>  **Natural Gas Drilling/Production** | | |

## 2. Petroleum Products

### A.  Regional Residential Heating Oil Model

Distillate fuel oil is consumed in several different sectors, including on-highway transportation, residential, commercial, industrial, and agricultural (Figure 1). Other applications include off-highway diesel, railroad, vessel bunkering, electric power, and oil company use.

Distillate fuel oil is a general classification for one of the petroleum fractions produced in crude oil distillation operations. First, distillate fuel is classified as No. 1, No. 2, or No. 4 fuel oil where the higher number denotes a heavier or more viscous liquid. Heating oil used in the residential sector is primarily No. 2 distillate fuel oil (about 1.5 percent is No. 1 fuel oil). Second, distillate fuel is classified as diesel fuel or fuel oil. The most significant distinction between diesel fuel and fuel oil is that diesel fuel has a maximum

allowed sulfur level of 500 parts per million or lower while fuel oil has a 5,000 parts per million maximum. Consequently, diesel fuel can be used as fuel oil but fuel oil generally cannot be used as diesel fuel. Heating oil used in the residential sector is fuel oil that has the higher sulfur limit.

Heating oil ranks as the third most important source of residential energy in the Nation, with nearly 8 percent of all households using heating oil as their primary space heating fuel (Energy Information Administration, *2001 Residential Energy Consumption Survey*, Table HC1-9a). Heating oil is also used by households for water heating.

The objective of the regional short-term residential heating oil model is to generate residential price forecasts for the four census districts: Northeast, South, Midwest, and West (see Appendix A1 for map). Regional residential heating oil prices are estimated as a function of the wholesale heating oil price, regional stocks, and regional demand (Figure 2). Regional residential heating oil prices are then aggregated to the U.S. level by weighting regional prices by estimated regional demands.


## B. Regional Residential Propane Model

Propane is consumed in several different sectors, including residential, commercial, petrochemical, industrial, and agricultural (Figure x). Other applications, which account for the remainder of propane demand, include use as fuel in internal combustion engines (generators, pumps, and fork lifts) and in gas utility peak-shaving. Propane ranks as the fourth most important source of residential energy in the Nation, with nearly 5 percent of all households using propane as their primary space heating fuel (Energy Information Administration, *2001 Residential Energy Consumption Survey*, Table HC1-9a). Propane is also used by households for water heating and cooking.

The objective of the regional short-term residential propane model is to generate residential price forecasts for the four census districts: Northeast, South, Midwest, and West. Regional residential propane prices are estimated as a function of the wholesale propane price to the petrochemical sector, regional stocks, and regional demand (Figure xx). Regional residential propane prices are then aggregated to the U.S. level by weighting regional prices by estimated regional demands.

## 3.  Natural Gas

## A.  Regional Natural Gas Demand

Natural gas demands and end-use prices are determined for 3 economic sectors (residential, commercial and industrial), the other principal source of natural gas consumption (i.e. for electric power) is determined in the Electricity Supply Model.  The natural gas portions of fuel demands for commercial and industrial electricity production and cogeneration are implicitly included in the regional commercial and industrial demand totals.  Except for a small amount of liquefied natural gas (LNG) exported to Japan from Alaska, natural gas exports are via pipeline to Mexico.  In addition to current domestic gas use and exports, demand for gas for domestic storage is another source of demand for new gas supply in RSTEM.   Regionality for natural gas storage is limited to the three-region approach used in the weekly reporting of underground storage, namely East consuming, West consuming, and West producing regions.  Not all of the important elements of the demand for natural gas storage are tracked in EIA data (or any published aggregate data).  Unlike liquids, natural gas can be compressed easily, and some of the demand for gas in storage is satisfied by compressing natural gas in the existing pipeline system, particularly as the period of peak demand (winter heating season) begins.  In the aggregate data, this phenomenon shows up as a sharp widening in the excess of reported supply over reported demand (including net underground storage builds) in the fourth quarter.  Aside from actual pipeline additions, which have to be filled in any case, it may be possible to avoid dealing directly with this particular measurement problem by assuming that the extent of compression is constant and assume that this particular source of demand may be captured in seasonal factors.

**Residential.**  The primary determinants of residential natural gas demand in a region are: occupied housing units with natural gas hookups; share of occupied housing units with natural gas hookups using natural gas as the primary energy source for heating; heating degree-days; real delivered residential per-unit natural gas prices; real personal income per household.  Autonomous trends in household natural gas use intensity are additional factors in residential demand related to residential building shell efficiencies and penetration of more efficient natural gas appliances (furnaces, water heaters, clothes dryers and ranges) in the household.  In RSTEM, the net effect of any such trends will be estimated econometrically.

**Commercial.**  The primary determinants of commercial natural gas demand in a region are: hours worked or real wage disbursements in commercial employment (as a proxy for commercial sector output); heating degree-days; real commercial-sector per-unit delivered natural gas prices; self-generating natural gas-fired capacity in the commercial sector.  Autonomous trends in commercial natural gas use intensity are additional factors in commercial demand related to commercial building shell efficiencies, average commercial floor-space per unit of output, and penetration of more efficient natural gas-using equipment in commercial establishments.  In RSTEM, the net effect of any such trends will be estimated econometrically.

**Industrial.**  The primary determinants of industrial natural gas demand in a region are: hours worked or real wage disbursements in industrial employment or industrial output as measured by the Federal Reserve Board; real industrial-sector per unit delivered natural gas prices; heating degree-days; self-generating natural gas-fired capacity in the industrial sector.  Autonomous trends in industrial natural gas use intensity are additional factors in industrial demand related to energy efficiency trends in industrial processes and equipment, and shifts in regional industrial output patterns among industry sectors of varying levels of natural gas use intensity per unit of output.  In RSTEM, the net effect of any such trends will be estimated econometrically.

**Storage.** The demand for natural gas storage (that is, net injections into underground storage facilities) follows from the behavioral relationship describing the aggregate market propensity to hold gas stocks under various seasonal and general market conditions.  In RSTEM, a system of equations determining the level of storage in three general regions will be estimated jointly, and the resulting per-period addition to stocks (positive during the injection season, negative during the withdrawal season) will be added to the natural gas demand total for each time period.  In general, natural gas storage levels exhibit very regular seasonal patterns and have generally understood seasonal shifts in variances.

## B.  Regional Natural Gas Supply

We assume that the U.S. natural gas market is sufficiently integrated geographically so that a key market location (the Henry Hub in Louisiana) provides price information that is sufficiently representative of the overall natural gas market supply/demand balance in the United States that it may be used as the benchmark price from which all major regional price levels and deviations may be inferred.  Additionally, we assume that regional price differentials relative to the benchmark price are generally stable and reasonably predictable, given some region-specific market characteristics (weather, excess pipeline capacity, etc.).  This assumption allows us to calculate regional spot prices for natural gas, and from these, region-specific wholesale and end-use prices for inclusion in regional natural gas demand estimation.

Natural gas supply (domestic production of dry natural gas and imports of gas from Canada plus LNG imports from various international sources plus supplemental gaseous fuels) is first treated at the national level in a procedure that determines an

equilibrium price for a key benchmark natural gas spot price: the spot price at the Henry Hub in Louisiana.  The Henry Hub price is determined by equilibrating aggregate demand for natural gas (sum of the regional sectoral demands plus natural gas used in the electric power sector plus lease and plant fuel use plus pipeline gas plus gross exports plus storage demand) with aggregate supply.

Then, the model determines regional natural gas spot price differentials **(for how many regions)** relative to the Henry Hub price, taking into account systematic historical and seasonal patterns in the differentials as well as any regional supply factors that may be useful in improving the overall accuracy of the estimating procedure.

The resulting regional spot prices are used to generate city gate prices for the demand regions **(how many demand regions**) or may be used directly as proxies for market prices (such as in the industrial sector) and used as determinants of delivered prices of natural gas to the electric power sector by electricity supply region.   The regional natural gas price determinations will feed back into the national level supply-price calculations by affecting regional demands which will feed back to the aggregate supply balance, and so on.

The basic natural gas market equilibrium condition in RSTEM requires that the Henry Hub price be such that supply equals demand for the national market as a whole.  The general approach in RSTEM is to obtain initial estimates of the Henry Hub spot price from an appropriately derived reduced form equation for the price, calculate the supply/demand imbalance from the demand and supply components in RSTEM and apply the implied net supply elasticity from the system to the percent imbalance in such a way that the spot price is adjusted to eliminate the excess supply.  The system is generally not amenable to direct analytical solutions for the equilibrium price but iterative application of the equilibrating procedure can be (and is) utilized in RSTEM.

**Drilling, Well Completions and Productive Capacity.**  RSTEM characterizes industry efforts at natural gas productive capacity development and utilization (wells drilled and dry gas production) at the national level by utilizing estimating relationships for active rigs drilling for natural gas (as a function of oil and gas revenues, spot natural gas prices, and other factors), well completions (as a function of rig efficiency trends, lagged relationship to rig activity, etc.), productive capacity (lagged relationship to well completions, cumulative production,  and other factors) and capacity utilization or production (as a function of capacity, current and lagged spot prices, and other factors).

**Imports**.  Natural gas imports are assumed to be a function of current and lagged spot prices, import capacity (separately for LNG and Canadian (and possibly Mexican) pipeline imports), and other factors.

**Supplemental Natural Gas Supply.**  Supplemental gaseous fuels supply, also included in the total supply for natural gas, is a relatively small component that consists of synthetic gas, refinery gas and some other components.  It is assumed that this source of supply is generally stable except for some regular seasonal components.

## 4. Electricity

In RSTEM, the greatest overall level of detail is provided for the electricity market. Electricity demands and end-use prices are determined for 4 economic sectors (residential, commercial, industrial, and other[1]) for 14 regions (9 Census Divisions plus a separate combined Hawaii and Alaska aggregation plus the four individual States of California, Florida, New York and Texas. Electricity supply (net generation by fuel source and energy consumption to produce electricity by fuel) is determined for the same 14 regions indicated for demand. Industrial-sector and commercial-sector production of electricity (and related fuel consumption) are determined for the 14 regions but are not expected to be a part of the main procedure for determining electricity output for the electric power sector.

## A. Regional Electricity Demand

**Residential.** The primary determinants of residential electricity demand in a region are: occupied housing units or households; share of occupied housing units or households using electricity as the primary energy source for heating; share of occupied housing units or households with installed air conditioning; cooling degree-days; heating degree-days; real delivered residential per-unit electricity charges; real personal income per household. Autonomous trends in household electricity use intensity are additional factors in residential demand related to residential building shell efficiencies and penetration of electricity-using appliances in the household. In RSTEM, the net effect of any such trends will be estimated econometrically.

**Commercial.** The primary determinants of commercial electricity demand in a region are: hours worked or real wage disbursements in commercial employment (as a proxy for commercial sector output); cooling degree-days; heating degree-days; real commercial-sector per-unit delivered electricity charges; self-generating capacity in the commercial sector. Autonomous trends in commercial electricity use intensity are additional factors in commercial demand related to commercial building shell efficiencies, average commercial floor-space per unit of output, and penetration of electricity-using equipment in commercial establishments. In RSTEM, the net effect of any such trends will be estimated econometrically.

**Industrial.** The primary determinants of industrial electricity demand in a region are: hours worked or real wage disbursements in industrial employment or industrial output

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[1] Beginning with 2003 data, EIA discontinued the reporting of the "Other" electricity sales sector and required respondents to allocate the information previously included in this category to the commercial, industrial and transportation sectors. Information on transportation sector electricity sales has, since 2004, been collected on a monthly basis. For electricity demand modeling in RSTEM, the old-basis sectors are maintained since the longer history is available that way, although a restatement to the new basis information is included and the reported information from RSTEM will normally be done on the new basis so as to match EIA's current publication standards. Once enough history is available for the new-basis categories, the RSTEM electricity demand equations will be restructured accordingly.

as measured by the Federal Reserve Board; real industrial-sector per unit delivered electricity charges; cooling degree-days; heating degree-days; self-generating capacity in the industrial sector. Autonomous trends in industrial electricity use intensity are additional factors in industrial demand related to energy efficiency trends in industrial processes and equipment, shifts in regional industrial output patterns among industry sectors of varying levels of electricity use intensity per unit of output, and penetration of general electricity-using equipment in industrial establishments. In RSTEM, the net effect of any such trends will be estimated econometrically.

**Other.** Other electricity demand in a region, which consists of electricity sales not designated as residential, commercial or industrial (such as municipal lighting and other general service as well as transportation), is assumed to be determined by general growth of economic activity in the region, as measured by gross regional product or other aggregate activity measures.

The demands for electricity relate to retail sales, or sales distributed by local distribution companies, either for own account or for the account of independent service providers. Two other demand components are: electricity generated by and consumed by an entity or facility, such as an industrial establishment (with either combined heat and power (CHP) or electric-only generating capability) or a commercial facility such as a University or other non-industrial facility; electricity generated by one entity and delivered directly to another entity, by-passing retail distribution. The bulk of such non-retail demand is in the industrial sector (approximately X percent in 2002). In RSTEM, the non-retail component of electricity demand is treated separately and at the national level.

## B. Hourly Load Profile Generator

Electricity consumption can be measured over a variety of time periods, with distinct, strong patterns of consumption exhibited, depending upon the time periods that are measured. In this model we are concerned with discerning the patterns or shape of electricity consumption, not the level of electricity consumption. Our primary objective is to reveal and forecast the hourly pattern or shape of consumption for the typical day in each month of the year for a variety of specially designed regions for electricity. In most cases the typical day's hourly patterns of consumption are very much determined by regular diurnal activities of electricity consumers that repeat for day after day over long periods of time. In addition, the most common variation in the day's hourly pattern has to do with weather influences, primarily the temperature from hour to hour. These hourly patterns also vary from month to month as major changes occur in typical daily behavior and as there are major climate changes over the year. In addition the hourly patterns will vary from region to region as demographics, infrastructure, and climate vary from region to region.

The purpose of the hourly electricity load shape forecasting module is to provide typical hourly load shapes to the Regional Short-Term Energy Model (RSTEM), for each month and RSTEM region. The regional monthly electricity demand level forecasts are

produced separately and independently within the Regional Short-Term Energy Model (RSTEM). The typical hourly load shapes describe the variations in electricity demand levels that are experienced on an electricity grid. The variations capture both the seasonal (monthly load shapes are estimated) and diurnal (typical variations over a twenty-four hour period) demand cycles within each region. It is these fluctuations in demand levels that warrant the utilization of various types of electricity generating plants with their associated differences in fuel demand and fixed and variable costs.

## C. Regional Electricity Supply and Prices

In RSTEM, electricity supply (net generation) is calculated for 14 regions, based on the 9 U.S. Census Divisions plus four States, namely California, New York, Florida and Texas. Nuclear and hydroelectric generation (by regions) are determined outside of STIFS and taken as exogenous. Historical patterns and recent trends are used to estimate non fossil fuel based generation sources other than hydroelectric and nuclear. A detailed dispatch model will be used to determine fossil fuel-based generation (coal, oil, natural gas) by region.

## D. Electricity Dispatch Model

The dispatch module predicts the composition of electricity supply within regions in the United States for the forecasting horizon (18-24 months). The dispatch model uses information on all the power generators in the United States to calculate the variable cost of operating for each power generator. The generators are then sorted, within a given region, from least-cost to highest-cost and are dispatched in that order based on the demand for electricity in any given period.

The model allows for trading between regions, as long as the regions are within the same interconnection. This is done by, rather than sorting all generation facilities within a given region, sorting all generating facilities within a given interconnection, or essentially adding the regional supply curves within each interconnection. The demand curves are also added, coming up with supply and demand curves for the whole interconnection. Dispatching decisions are then made based on the variable costs of all facilities within that interconnection. Each facility is identified with its fuel type and the region in which it is located, so once dispatching decisions are made, the model indicates how much and what types of generation were dispatched from each region. Additional modifications to this scenario are made to acknowledge transmission, environmental, and engineering constraints.

## E. Regional Electricity End-Use Prices

End use prices for electricity may not have a particularly straightforward relationship to wholesale or spot prices for the underlying commodity. Retail electric rates are still heavily regulated at the State level (particularly for the residential sector), and average costs of production and the particular requirements of State regulators are generally more important in the determination of the prices that consumers see than marginal

supply costs, which may or may not be presumed to be reasonably well represented in spot electricity prices.  Thus, consumers in areas that have an abundance of low cost hydroelectric output may see much lower electricity prices than other regions, even if marginal supply costs are roughly equivalent. Thus, much of the analysis needed to generate good estimating equations for the electricity prices for the electricity demand regions will focus on the particular patterns of historical average price behavior from the time series in those regions rather than on marginal supply costs in the relevant electricity supply regions.  Nevertheless, an attempt to relate marginal electricity production costs to spot electricity price patterns should be made.  In future versions of RSTEM, regional spot electricity prices will be considered as factors, along with average fuel costs in the supply regions and other variables as determinants of retail electricity prices.

## F.  Regional Electric Power Sector Fuel Cost Module

The Regional Power Sector Fuel Cost Module (RSTPSFCM) of the Regional Short-Term Energy Model (RSTEM) provides a procedure for calculating short-term delivered average fuel costs to the electric power sector (electric utilities and independent power producers) by RSTEM electricity supply region.  In RSTEM, there are 13 electricity supply regions in the Lower-48 States plus a separate accounting for the combined activities of Alaska and Hawaii.  Fuel costs by region are calculated only for the Lower-48.  Four categories of average monthly fuel cost are tracked, including: coal; natural gas; residual fuel oil; and distillate fuel.  Regional and national average natural gas and fuel oil spot and wholesale prices determined in other RSTEM modules are used as key determinants of the regional power sector delivered costs

As with the rest of RSTEM, the RSTPSFCM is designed to generate monthly forecasts, in this case of per-unit average costs for fossil fuels in dollars per million Btu delivered by 13 electricity supply regions.

The power sector fossil fuel costs used in RSTEM are taken from FERC Form 423 and EIA Form 423, "Cost and Quality of Fuels Survey(?)."  Costs associated with deliveries to independent power producers are proprietary, and would not be reportable for some of the electricity supply regions for some periods.  For RSTPSFCM, only average costs for deliveries to electric utilities are used.

## G.  Regional Electricity Generating Capacity

For RSTEM, generating capacity by fuel by region will be predetermined, based on capacity reported in EIA's Form EIA-860, with recent historical values and forecasts provided by utilizing EIA tracking of recent additions and planned additions.  Capacity tracking and projections by fuel by region is an important part of the regional short-term forecasting program, and will require coordination between the Office of Energy Markets and End Use, the Office of Integrated Analysis and Forecasting and the Office of Coal, Nuclear, Electric and Alternate Fuels to insure consistency with forecasts and assumptions about capacity reported in all EIA Offices.

## 5. Macro Bridge

The RSTEM Macro Bridge is designed to address the problem of maintaining regional macroeconomic forecasts (which are only available on a quarterly basis) consistent with monthly national macroeconomic forecasts, the latter of which are to serve as the basis for EIA's assumptions about growth in aggregate output, income and employment for its monthly model simulations used in the Short-Term Energy Outlook. Both the national and regional macroeconomic forecasts are supplied by Global Insight (GI). Once each quarter, the baseline forecasts for both the regional and national macroeconomic forecasts are expected to be entirely consistent. For interim monthly forecasts, however, a procedure is required to adjust the quarterly regional forecasts so that they reflect aggregate economic activity that is consistent with the monthly national forecasts. The Macro Bridge program utilizes simple scaling routines that align/and update GI regional macroeconomic data and forecasts with monthly macroeconomic data and forecast updates from the GI quarterly model of the U.S. economy.

## 6. Appendices

## A. Electricity Dispatch Model Calibration

The generic nature of the regional dispatching model allows it to utilize all the relevant EIA electricity data and to capture historical dispatching patterns. This chapter analyzes available data at generator level and put them in a framework that shed lights on operators' dispatching behavior. A systematic calibration process then uses the findings to modify the dispatching order of power plants in each region. The short-term energy outlook makes 24 monthly projections from the date of publication. Both forecasting period and time interval are short, therefore, the regional electricity model uses only near term monthly data, 2002 and 2003 data for model calibration.

# RSTEM Data Flow and Modeling Process

Regional Macro Data/Forecasts (GI)

Regional Weather (NOAA)

EIA Regional Energy Quantity Data

EIA Regional Energy Price/Cost Data

World Oil Price Assumptions

Other Input Data

**Regional Data Prep Program**

Econometric Model Estimation

Petroleum Demand
Petroleum Supply
Petroleum Prices: motor gasoline, heating oil and propane
Natural Gas Demand: regional end use
Natural Gas Prices: regional spot, citygate, end use
Electricity Demand: regional end use
Electricity Prices: regional end use
Power Sector Fuel Cost: regional coal, dist., residual, and natural gas
Coal Demand
Coal Supply
Other

Update Econometric Model Inputs

Electricity Load Parameters

EIA Electric Generating Capacity Data

**Electricity Dispatch Model**

*Generation by Source*

**Econometric Model Forecasts**

*Load, Fuel Costs*

*Load, Fuel Costs*

**Convergence Check**

No    Yes

**Save Final Outputs, Generate Reports**