ENERGY 2020

Electricity Supply Module Documentation

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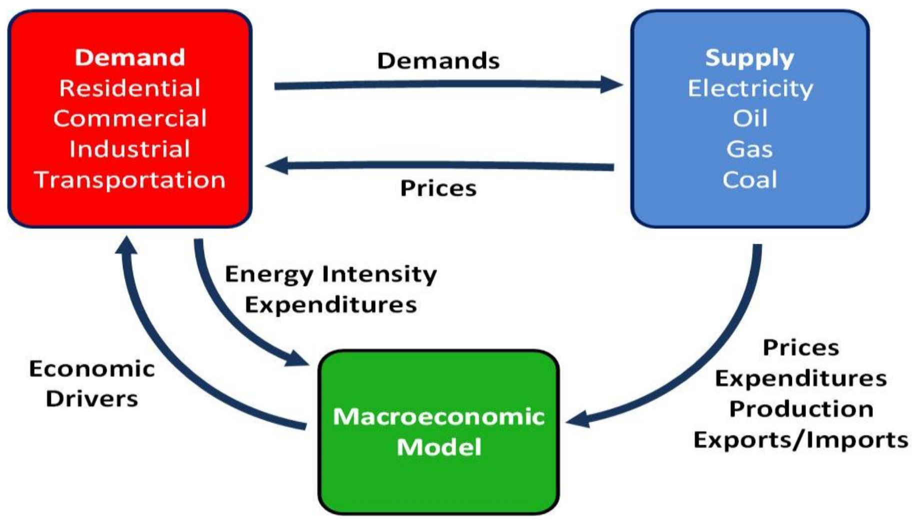
1. Introduction

ENERGY 2020 simulates the North American energy system providing long-range energy and emissions forecasts and the ability to analyze energy-related policies. Three sectors make up the core of ENERGY 2020 – a demand sector, a supply sector, and a macroeconomic sector. The relationship among these three sectors is shown in Figure 1. The energy supply sector's major modules (electricity, oil, gas, and coal) receive energy demands from the demand sector and, in turn, send resulting energy prices back as input to the demand sector. When ENERGY 2020 is linked to a macroeconomic model, the supply sector sends energy prices, expenditures, production, imports and exports to the macroeconomic model. The macroeconomic model combines these supply sector inputs with energy intensity and expenditure inputs from the demand sector to estimate economic impacts which then are sent back to the demand sector as drivers for energy demand.

Figure 1. ENERGY 2020 Model Linkages



ENERGY 2020's supply sector is made up of several major modules, including electricity, oil and natural gas, and coal supply in addition to other smaller supply modules, such as refined petroleum products, ethanol, and land-fill gas. This chapter specifically focuses on documentation of the electric supply module – both its methodology and model code.

The electric supply module endogenously simulates the capacity expansion, generation, fuel usage, transmission and distribution, emissions, and pricing of electricity. For each year of model execution, this module receives energy demands from the demand module, converts these demands to a system load duration curve, builds new generation capacity based on load growth at wholesale prices, dispatches individual generating units to meet demand, generates a system marginal price, simulates transmission flows, calculates generation, fuel use and emissions for each unit, simulates the cost of power to each retail company, or load serving entity (LSE), through contracts and wholesale power purchases, and calculates retail electric prices from LSE power costs, LSE other costs and local regulatory factors. The model dispatches plants according to specified rules, whether they are optimal or heuristic, and simulates transmission constraints when determining dispatch. The dispatch routine selects critical hours along seasonal load duration curves as a way to provide a quick but accurate determination of system generation. The key outputs include electricity prices which are sent to the demand module, fuel consumption which is sent to the oil, gas, and coal supply modules and expenditures, production, imports and exports which are sent to the macroeconomic module along with prices.

The electric supply module is comprised of ten submodules, including 1) load curves, 2) contract development, 3) retail purchases, 4) pollution costs, 5) capacity expansion, 6) generation dispatch, 7) fuel usage, 8) pollution, 9) retail power costs, and 10) electric prices.

Figure 2 provides a list of the submodules that make up the electric supply sector and are shown in the order of model execution. Each of these submodules is executed from inside ENERGY 2020's control procedure for electric supply, *RunControl*, which is housed in the file named *EControl.src*. The objective of each of the electric supply submodules can be summarized as follows:

1. The **load curve** submodule processes electricity demand obtained from the demand sector to construct load curves which are needed for calculations within the Retail Purchases, Capacity Expansion, Generation Dispatch, and Electric Price submodules.

2. The **contract development** submodule determines the capacity and energy available for contracts made between retail and generation companies along with their associated costs.

3. The **retail purchases** submodule assigns the amount of capacity and energy that get purchased by retail companies from contracts and the wholesale market.

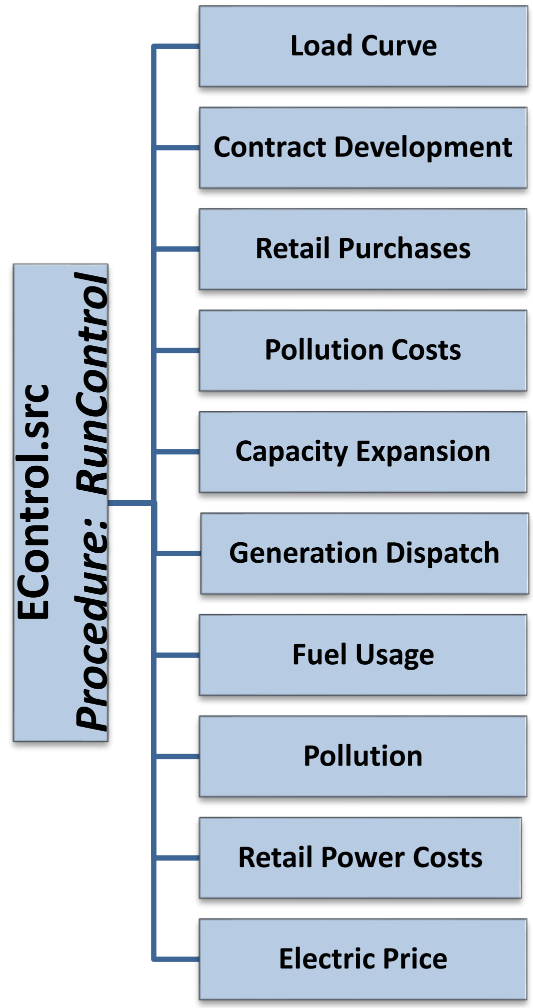
4. The **pollution costs** submodule calculates the cost of emissions from various fuels and plant types to be used in comparison options for capacity expansion.

5. The **capacity expansion** submodule projects the construction of new generating plants based on meeting a reserve margin and/or based on wholesale prices. Outputs include capacity under construction and total unit generating capacity which is used as input to the generation dispatch module.

6. The **generation dispatch** submodule dispatches the available generating units using pre-specified dispatch assumptions and minimizing the overall cost to the system. Outputs include generation dispatched, transmission flows, wholesale prices, imports, and exports.

7. The **fuel usage** submodule summarizes the outputs from the electric generation dispatch into various aggregations for use by other modules within the model.

Figure 2. Electric Supply Submodules



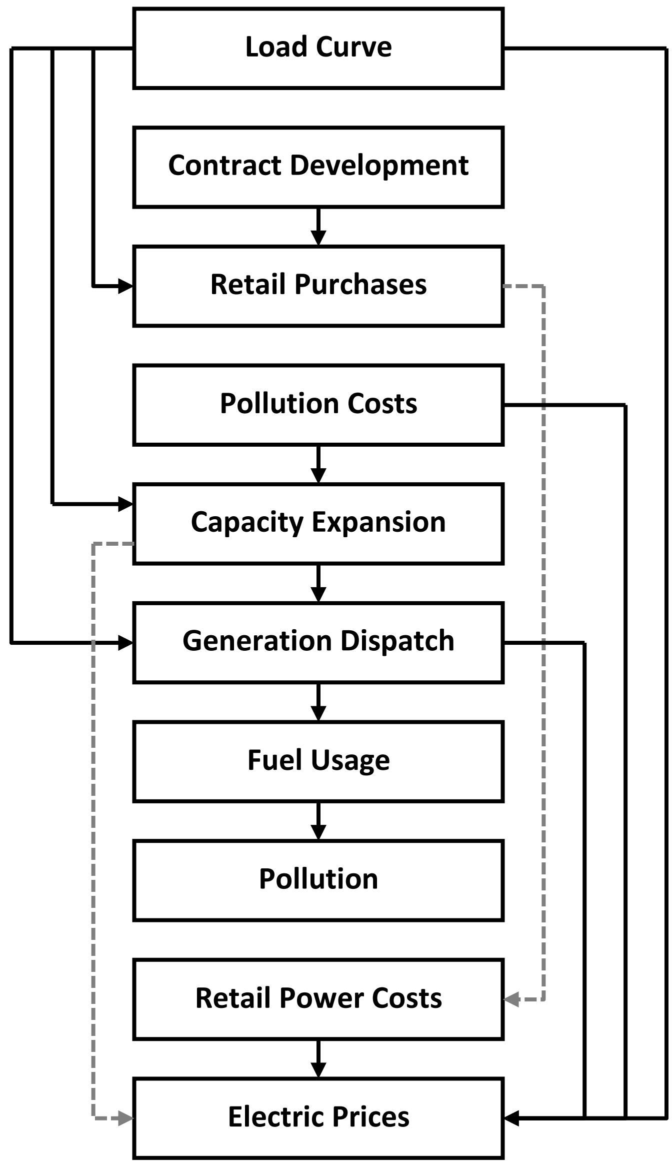
8. The **pollution** submodule calculates the emissions based on the fuel usage dispatched in the generation dispatch submodule.

9. The **retail power costs** submodule calculates the cost of the retail purchases using inputs from the costs determined in the contract development submodule combined with the amount of capacity and energy purchased.

10. The **electric pricing** submodule determines the electricity prices for the current year of execution for each retail company based on the unit cost, delivery charge and other adjustments.

The information transfers between the electric supply submodules are shown in Figure 3. Load curve outputs are sent as input to retail purchases, capacity expansion, generation dispatch, and electric prices. The capacity and energy available for contracts from contract development are sent to retail purchases. The actual amount of power purchased from contracts and the spot market from retail purchases are sent to retail power costs. Outputs from pollution costs are sent to capacity expansion and electric prices. The unit capacity outputs from capacity expansion are sent to generation dispatch. Marginal prices and generation dispatched calculated in generation dispatch are sent to fuel usage and electric prices. Outputs from fuel usage are inputs to pollution. Finally, the retail power costs outputs are used as inputs to electric prices along with the pollution costs outputs and marginal prices outputs from generation dispatch.

Figure 3: Linkages in Electric Supply Module

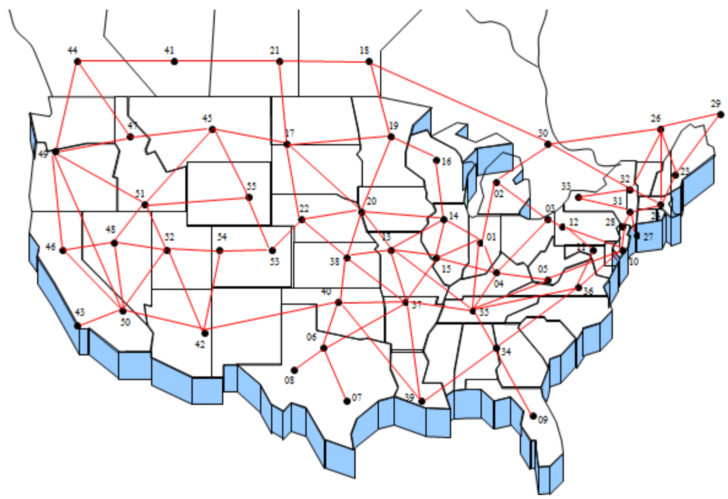


Structure of Electric System

The electric supply module contains several building blocks including generation units, generating companies, retail companies (or load serving entities LSEs), transmission demand centers (geographic areas) and power contracts. The electric system in ENERGY 2020 is simulated as a set of nodes connected by transmission lines. The electrical demand and electric generating units are located on the nodes. Each node consists of its own unique, specified demand, which is met by a pool of resources consisting of the generating units as well as emergency generation. The interpretation of emergency power includes brownouts, non-utility generation purposed to feeding the grid (such as hospital generation), and other non-standard generation. Each resource has an associated cost, a bid price and a capacity.

Nodes are connected by transmission lines containing a variety of line capacities, transmission efficiencies, and wheeling costs. The actual transmission nodes and lines defined in ENERGY 2020 can be customized; however, the standard version of the model has 110 nodes represented across North America which are typically aggregated into a smaller number of nodes of interest. Figure 4 illustrates an example of a transmission network represented in ENERGY 2020.

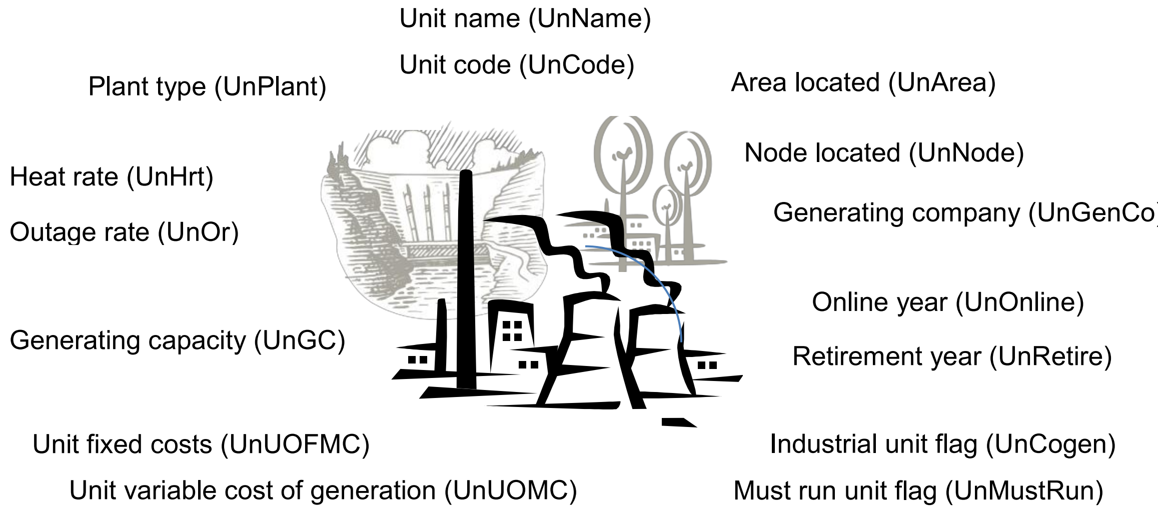
Figure 4. Sample Transmission Network in ENERGY 2020



A generating unit is able to send electricity to neighboring nodes via the transmission lines. Each of these inputs is used to find the optimal solution of generation, flows, and the resulting nodal prices. The entire geographic area of the model is dispatched as a single system.

Each electric generating unit is exogenously-specified with defining characteristics. These characteristics include a name, the node in which they are located, the type of plant, the heat rate, the online and retirement years of the unit, and the generating capacity. Additionally, units are assigned an outage rate, a fixed cost, and a variable cost. The units may be flagged as “industrial”, meaning it is self-generating and does not provide generation to the electric grid. Units may also be flagged as “must run”, meaning the unit always runs. The exogenously-specified characteristics of the electric generating units are summarized in Figure 5 below.

Figure 5: Exogenously-specified characteristics of generating units



Each individual unit can be simulated although smaller units can also be aggregated by type and transmission mode. Currently the number of electric units represented in the model consists of roughly 1,300 Canadian units and an aggregate representation of US at just over 500 units.

The number of generating companies and retail companies (LSEs) simulated varies by model implementation but range from 10 to 40.

The generating companies have a set of generating units, a capacity expansion strategy, a bidding strategy, contracts with retail companies (LSEs), generation, fuel usage, and emissions. The retail companies have contracts with generating companies, sales to demand areas, and a retail cost structure. The contracts have a generating company and a retail company, a capacity, a variable cost, and a fixed cost. The transmission nodes have generating units and demands from the geographic areas. The demand centers are geographic areas with relationships with transmissions nodes and retail companies. The demand center prices are a function of the retail company prices serving their area.

Electric Supply Source Code

The files that contain the ENERGY 2020 source code that simulate each of the electric supply submodules are named with an 'E' prefix and are housed within the Engine subdirectory. The file name of each electric supply submodule is listed in Table 1.

Table 1: Submodule File Names

File Name	Submodule Model Code
ELoadCurve.src	Electric load curve submodule
EContractDevelopment.src	Contract development submodule
ERetailPurchases.src	Retail purchases submodule
EPollution.src	Pollution submodule, pollution costs submodule
ECapacityExpansion.src	Capacity expansion submodule
EDispatch.src	Electric generation dispatch submodule
EFuelUse.src	Fuel use submodule
ERetailPowerCosts.src	Retail power costs submodule
ElectricPrice.src	Electric pricing submodule

Load Curve Submodule

The development of the load curve begins in the demand sectors where enduse demands for electricity are multiplied by a load shape factor to produce enduse electric demands for the peak, average and minimum points on the load duration curve for each enduse, economic category and geographic area. These enduse load curves are combined with street lighting and miscellaneous electric demands to produce a system load curve for each area.

The load curve for each economic category is allocated to each retail company using historical relationships or retail prices if retail competition is active. The load curve is also allocated from each geographical area to the transmission nodes. A transmission loss factor is applied to the electric sales from the demand sectors. Once the load curves are allocated to transmission nodes, the peak energy demands for each of six time periods are computed. These six time periods for each season are used to dispatch the generating units. The six time periods are peak, near peak, high intermediate, low intermediate, high base load, and low base load.

Contract Development Submodule

The purpose of the contract development submodule is to set up the specifications of potential retail company contracts with generating companies. The specifications include minimum and maximum amounts of capacity to be purchased by each retail company, the energy available for each contract, and the cost of capacity and energy purchased through contracts.

Retail Purchases Submodule

With the contract costs, capacity, and energy limits determined, the model is now ready to create contracts to meet electric demands. In this section, retail companies have the option to purchase electricity either from contracts with generating companies or through the spot market.

Contracts for each retail company are dispatched starting with the lowest cost contracts until all electricity needs are met or no more available contracts exist in which case retail companies purchase electricity from the spot market. The amount of electricity purchased either from contracts or the spot market is saved for use in other parts of the model, including calculating the final electric price.

Pollution Costs Submodule

The pollution costs submodule determines the amount of emission reductions required by electric utilities and applies reductions at the individual unit level. Marginal and average emissions coefficients are recalculated for the sector as a whole along with an estimation of the costs of the reduction based on abatement curves. The submodule offers the user different options (such as setting the cost of emissions permits or setting a specific reduction target) to determine how reductions for each unit are calculated.

Capacity Expansion Submodule

The decision to build new generation capacity involves many factors. ENERGY 2020 includes a variety of algorithms to simulate the decision to build new capacity. These algorithms include information on wholesale prices, desired reserve margins, the cost of new capacity (construction, operating, and environmental costs), political and social preferences, regulations, standards, and subsidies. The model is adjusted and customized to simulate the decision making process at a particular time and location.

One method of building new capacity is to build whenever capacity is lower than a desired reserve margin. The model forecasts the expected demand a few years into the future applying an expected growth rate to current year's peak demand. The number of years which are forecasted depends on the construction time of the units being built. The forecasted peak demand is compared to the existing capacity (derated for intermittent sources), capacity to be retired, and capacity under construction to decide the amount of new capacity.

An alternative method of building new capacity is to build based on the wholesale price of power. As the wholesale price rises, new capacity will be constructed even if the reserve margin is higher than "desired". Conversely, if the wholesale price is low, then new capacity will not be constructed even if it is "needed".

After forecasting the construction of new capacity, the submodule passes total available capacity to the electricity generation dispatch submodule and new capacity expenses to the electric pricing submodule.

Generation Dispatch Submodule

The dispatching of electric units is simulated using a linear program (LP) where the objective function minimizes the cost of production subject to the constraints of meeting demand using available capacity within the limits of the transmission system. The production costs include the bid prices of the units and the cost of moving power across the transmission network. Generating units are derated based on the unit outage rates before they are bid into the system. The full derated capacity is generally bid into the system. Most units are bid at their marginal costs although other options are available. Some units (nuclear) may have a reported fuel cost which overstates their marginal costs. These units can be bid at less than their marginal costs. Fixed cost may also be included in the bid, if desired. Bids can vary by period. Market bids can be set to maximize generating company income. The generating companies modify their bids (up and down) and monitor their net revenue. If net revenues go up, then the generating company continues to modify their bids.

Transmission flows are a function of the dispatch algorithm; however exogenous "contract flows" can be added to force the flow of electricity between specific nodes. This may be needed when significant amount of storage hydro is available since the allocation of the water includes consideration of "contract flows".

Imports and Exports

Electricity imports and exports are calculated as part of the LP in the electric generation dispatch submodule. Loading on the transmission lines between nodes comes out of the LP as a variable called HDLLoad. The procedure *Flows* in the electric generation submodule stores the flows between the US and Canada obtained from the LP to an import variable (ExpPurchases) and an export variable (ExpSales).

Imports and exports can be specified exogenously (using the variable HDXLoad) for instances where there are known levels of imports or exports, such as through contracts. The exogenously-specified values are added to the flows determined by the LP.

Cogeneration

The types of electric generating units represented in the model include all significant generators, including both utility and industrial boilers and generators. By contrast, reported electricity consumption information tends to be based on metered electricity sales, and as such are net of self-generation. Total electricity consumption and generation will generally be slightly higher than reported electricity sales. It is therefore important in calibrating the model with historic electricity consumption that existing generation used as industrial or self-generation be appropriately identified.

The method of calculating cogeneration demands in the model is specified by a switch and may take different forms. In one option, the demand module endogenously calculates sector-level cogeneration demand and costs. Another option available is to calculate cogeneration at the individual unit level rather than the sector level. If this option is selected, the unit-level cogeneration is determined in the electric dispatch submodule is aggregated up to the sector level in the demand module.

When unit-level cogeneration is used, the industrial cogeneration units are represented in the list of electric generating units. Each of the industrial generating units has a capacity, the amount of cogeneration is determined as the portion of that capacity remaining after own use and outage rates. The unit demand then is determined from the capacity available. Then the cogeneration routine in the demand module gets called and aggregates the unit cogeneration demand up to the sector level totals.

Fuel Usage Submodule

The objective of the fuel usage submodule is to aggregate and summarize several output variables from the previously executed electric supply submodules. In particular, fuel consumed by electric units based on the generation dispatched in the electric generation dispatch submodule is summarized into specific fuel usage variables for use in other submodules, such as pollution.

Pollution Submodule

The objective of the pollution submodule is twofold. First, the submodule calculates the emissions from electricity generation on the unit level. Second, the submodule applies various pollution related policies. These include but are not limited to offsets, emissions-related capital retirements and construction, Alberta CASA policies, and the assignment of gratis permits. Emissions are a function of fuel usage and an emission factor. The emission factor depends on the emissions reduction technology.

Retail Power Costs Submodule

The purpose of the retail power costs submodule is to determine the costs of the retail companies' power purchases. With costs and the amount of power purchased from contracts and the spot market determined, the procedure *ERetailPowerCosts* calculates the final cost of purchasing power from the generating company for each retail company.

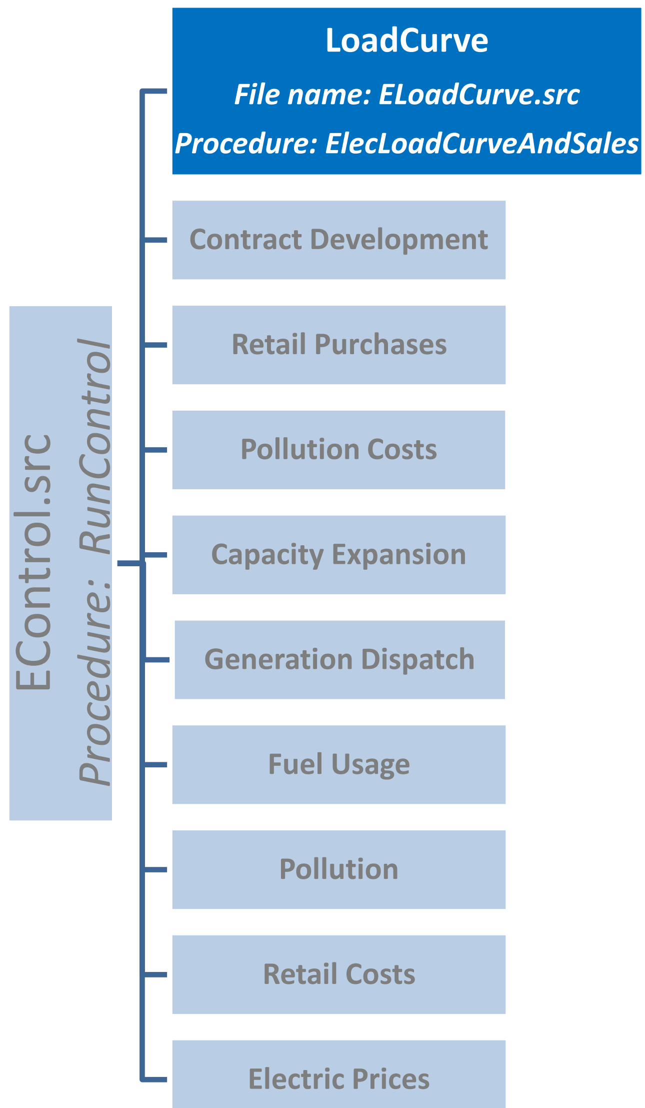
Electric Pricing Submodule

The purpose of the electric price submodule is to calculate the final price of electricity for each retail company based on the unit cost, delivery charge, and other adjustments. The price calculated in this submodule is the retail price of electricity – the final price that is passed to the customer purchasing power. The retail electric price is key as an input for the decision making process of consumers in the demand sector.

2. Load Curve Submodule

ELoadCurve.src contains the source code and procedures that make up the load curve submodule within the electric supply module. The load curve submodule's main procedure is named *ElecLoadCurvesAndSales* and is called from the *RunControl* procedure inside EControl.src. It is the first submodule called in the electric supply module.

Figure 6: Load Curve in Electric Supply

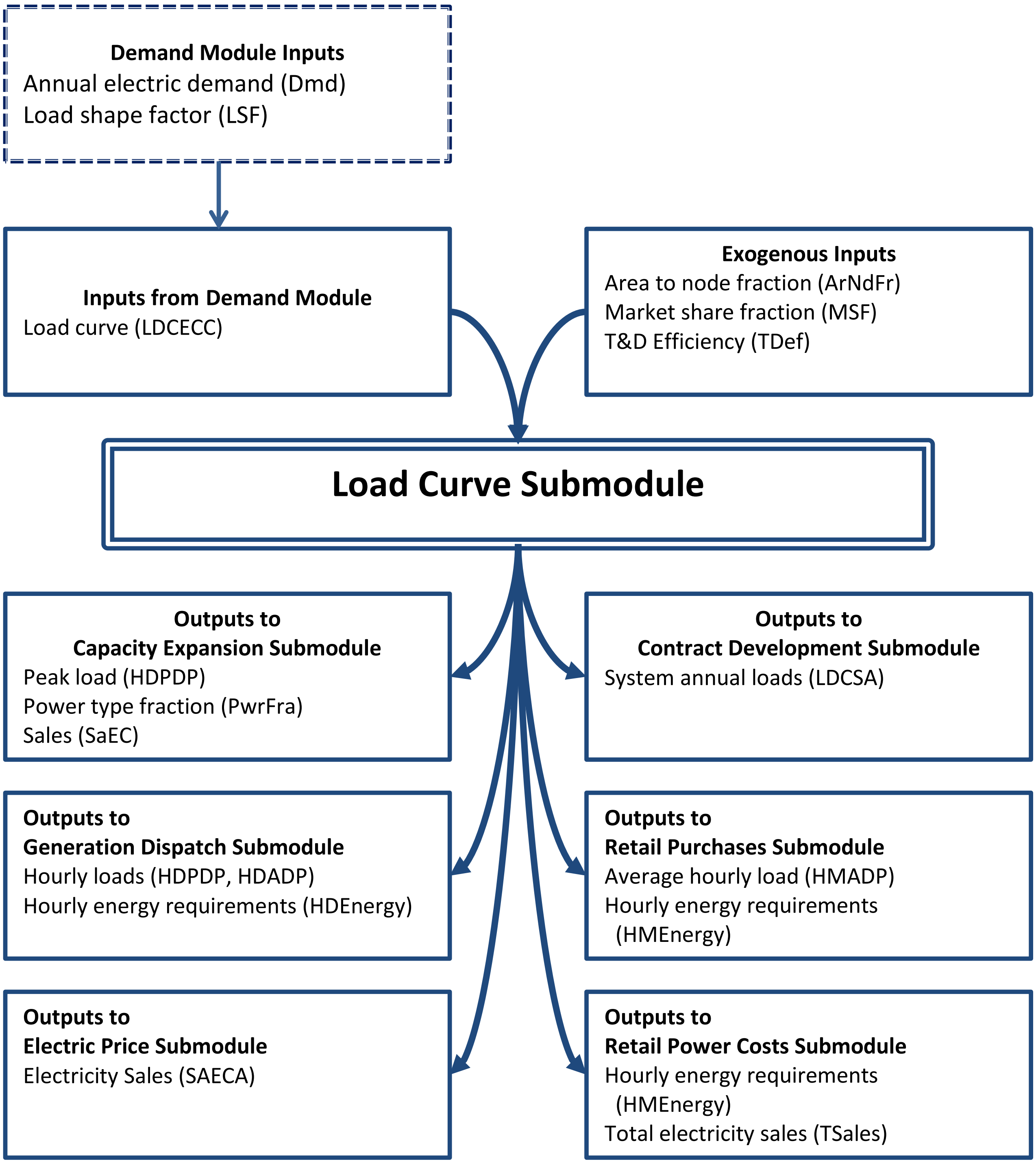


Submodule Objective

The objective of the load curve submodule is to aggregate and transform outputs from the demand sector into forms more useful to the electric sector. Specifically, hourly load demands which are used in the dispatch of electric generation; aggregate peak, average, and minimum loads used in determining expansion of generation capacity; and electric sales useful in the calculation of electricity prices.

The key input and output variables of the load curve submodule are shown in Figure 7.

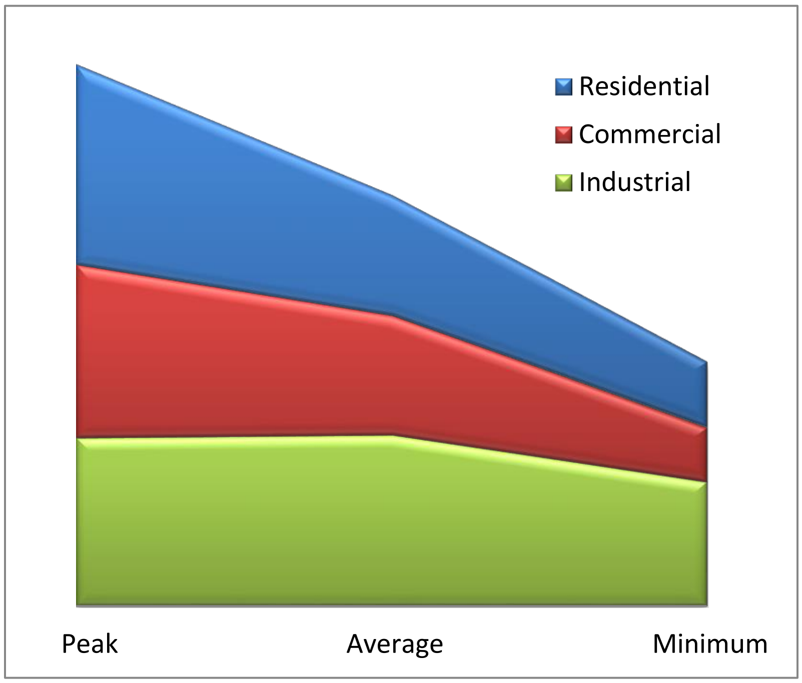
Figure 7. Load Curve Submodule Diagram of Inputs and Outputs



Submodule Methodology

The development of the load curve begins in the demand modules of the model where enduse demands (Dmd) for electricity are multiplied times a load shape factor (LSF) to produce enduse electric demands (LDCECC). These represent the contribution to peak, average and minimum points on the load duration curve for each enduse, economic category and geographic area. These enduse load curves are combined with a street lighting and miscellaneous electric demands to produce a system load curve for each area.

Figure 8. Sample LDCECC - 2010 Total Canada Electricity Sales



The load curve submodule in the electric supply module takes these loads for each economic category (LDCECC) and, combining them across industries, allocates the total electric load to each retail company using historical relationships or retail prices if retail competition is active. The load curve is also allocated from each geographical area to the transmission nodes. The load curves based on geographical area and transmission node are used to calculate the total electricity sales. These are chiefly used in pricing and as direct outputs. Next, a transmission loss factor is applied to the accumulated load curves in order to create the system load curve (LDCMS). Specifically, this is the system load curve for electricity marketers and retailers, which is a distinction from earlier incarnations of the model where different kinds of electric companies could have their own load curves.

The load curve is then used to create variables relevant to both capacity expansion and generation dispatch. For capacity applications, the load curve submodule creates power fractions (PwrFra), which calculates the percentages of loads in peak, intermediate, and baseload categories. Due to a desire for more granular pricing information, generation dispatch uses more detailed information on load demands. This begins with use of six time periods for each season—peak, near peak, high intermediate, low intermediate, high base load, and low base load. For each time period, peak and average loads are calculated, as well as the energy requirements.

Submodule Procedures

The procedures described in this section pertain only to those load curve procedures that are housed in the electric supply sector. As discussed in above, at the point when the electric supply sector is executed, the demand sector has allocated the enduse demands (Dmd) to hours, months, and time periods into a load curve (LDECC) using load shape factors (LSF) applied to the demand. The electric load curve submodule in the electric sector performs further transformations of the load curve into retail companies, area, and node splits needed by the other submodules within the electric supply sector, such as capacity expansion, generation dispatch, and electric prices. Above, Figure 9 shows the procedures that make up the electric load curve submodule.

Figure 9: Procedure ElectricLoadCurveAndSales in ELoadCurve.src

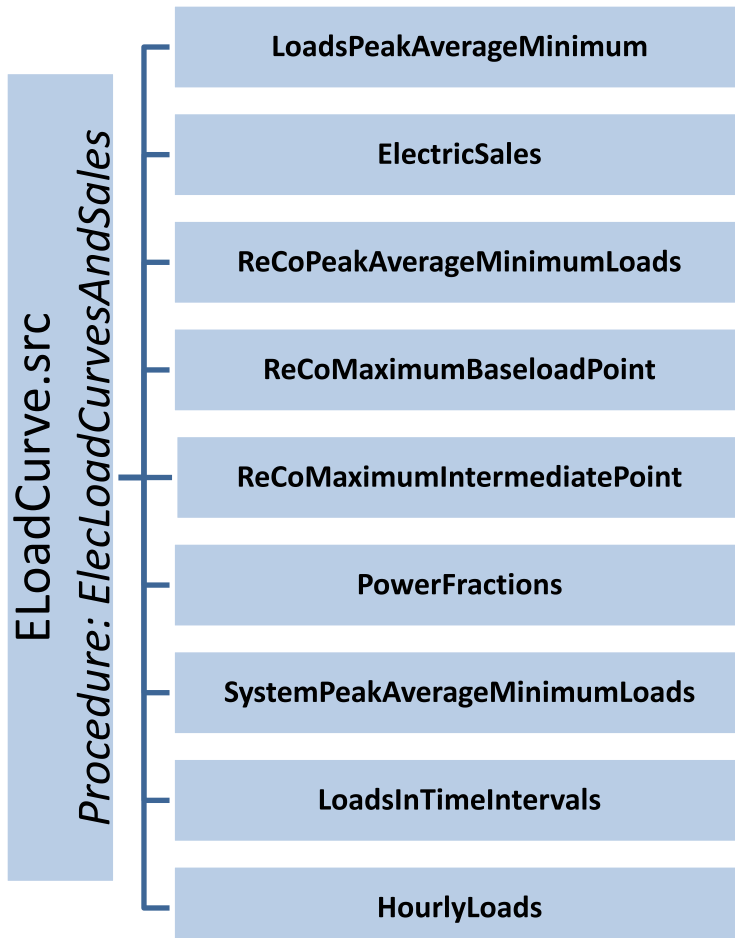


Table 2 provides a summary description of each of the procedures within the electric load curve submodule along with the key outputs for each.

Table 2: Description of Load Curve Procedures

Procedure Description	Key Outputs
1. LoadsPeakAverageMinimum Takes the electric load curve from the demand sector (LDCECC) and allocates the loads using the Area/Node split fractions (ArNdFr), the input market share (XMSF) and the T&D efficiency (TDEF) into intermediate version of load curve (LDCDN), Area Electric Load Curve (LDCAr), Node Electric Load Curve (LDCNd), and the marketer system load curve (LDCMS). Area and Node LoadCurves are used in procedure *ElectricSales*; Marketer System Loads (LDCMS) are principally used in procedures *ReCoPeakAverageMinimumLoads* and *LoadsInTime Intervals*.	Electric Load Curve (LDCAr), Node Electric Load Curve (LDCNd), and the Marketer System Load Curve (LDCMS)
2. ElectricSales Calculates the Sales from various Loads; Node Sales (SAECN) from Node Loads (LDCNd), Area Sales (SAECA) from Area Loads (LDCAr), Sales by Economic Category (SAEC) {a different one from[R/C/I/T]Loads.src} from Node Sales, Class Sales (SACL) from Sales by Economic Category, and Total Sales (TSALES) from Class Sales.	The several sales variables (SAECN, SAECA, SAEC, SACL, TSales) are used in electric price calculations and as outputs.
3. ReCoPeakAverageMinimumLoads Calculates Minimum, Average, and Peak Demand Loads (MDP, ADP, and PDP) from the marketer system loads (LDCMS).	The loads (MDP, ADP, and PDP) are used for load points below and in the procedure *PowerFractions*.
4. ReCoMaximumBaseloadPoint Calculates the Maximum Baseload Point on the LDC (MBP) from the ReCo Loads.	The Maximum Baseload Point (MBP) is used in the procedure *PowerFractions*.

Procedure Description	Key Outputs
5. ReCoMaximumIntermediatePoint Calculates the maximum intermediate load point on the LDC (MILP) from the ReCo loads.	The maximum intermediate load point (MILP) is used in the procedure *PowerFractions*.
6. PowerFractions Calculates the power type fractions (PwrFra) from the minimum, average, and peak demand loads (MDP, ADP, PDP). Currently, a bug switch adjusts how PwrFra is calculated from these loads.	Power fractions (PwrFra) are used in electric capacity expansion.
7. SystemAnnualPeakAverageMinimumLoads Calculates the system annual loads (LDCSA) – that is, the highest peak loads from the entire year, lowest minimum loads from the entire year, and the mean average load across the months of the year – from the retail loads (MDP, ADP, PDP).	System annual loads (LDCSA) are used in contract development.
8. LoadsInTimeIntervals Interpolates a load curve from the peak, average, and minimum points on the marketer loads. The curve will be sliced into six time periods; for each time period the average load, the peak demand, and the energy requirements are calculated.	Interval loads and energy requirements (HMPDP, HMADP, HMEnergy) are used in the procedure *HourlyLoads.*
9. HourlyLoads Takes the interval loads (HMPDP, HMADP) and energy requirements (HMEnergy) of *LoadsPerInterval*, as well as the Power Sold to Grid (PSoECC) and creates the hourly loads and energy requirements used in the generation dispatch submodule (HDPDP, HDADP, HDEnergy) by incorporating the energy and peak power sold to grid (PSoEnergy, PSoPDP).	Hourly loads and energy requirements (HDPDP, HDADP, HDEnergy) used in the generation dispatch.

Each of the individual procedures summarized in the table above are described in more detail in the following sections.

Procedure LoadsPeakAverageMinimum

This procedure takes as input the electric load curve from the demand sector (LDCECC). It allocates the loads to retail companies and transmission nodes using area/node split fractions (ArNdFr), a market share fraction (MSF). The resulting load curves include an area load curve by economic category, area, and retail company (LDCAr) and a load curve by economic category, transmission node, and retail company (LDCNd); these are used as output and in sales calculations.

A system load duration curve (LDCMS) is also created from the demand sector load curve. The contributions from each economic category are summed and T&D efficiency (TDEF) is incorporated into the final load duration curve. This will be the principle load curve used in calculation of peak, average, and minimum points on the curve, power fractions, and time period based energy requirements and peaks.

Each of these variables is used by other procedures within the electric supply sector. The LDCMS variable is used as an input to create the ReCo loads and the Hourly loads in procedures *ReCoPeakAverageMinimumLoads* and *LoadsInTimeIntervals*, as well as in EDispatch for emergency power availability. The LDCAr and LDCNd variables are as input to *ElectricSales* to create Area and Node sales variables, respectively.

Key equations in *LoadsPeakAverageMinimum* are:

Key Equations: ***LoadsPeak Average Minimum***

Load curve by ECC, day type, month, node, and retail company:

$LDCNd = \sum_{Area} (LDCECC*ArNdFr*MSF)$

Load curve by ECC, day type, month, area, and retail company:

$LDCAr = \sum_{Node} (LDCECC*ArNdFr*MSF)$

System load curve by day type, month, node, and retail company:

$LDCMS = \sum_{Area,ECC} (LDCECC*ArNdFr*MSF*(1-RofWSw)/TDEF)$

a. $LDCMS_{Minimum} = \mathit{min} (LDCMS_{Minimum}, LDCMS_{Average} *0.90)$

Table 3 summarizes the variable names and definitions of the inputs and outputs to this procedure.

Table 3: Input and Output Variables - LoadsPeakAverageMinimum

***LoadsPeakAverageMinimum* Inputs and Outputs**
Key inputs
ArNdFr (Area,Node,Year) = Fraction of the Area in each Node (MW/MW)
LDCECC (ECC,Hour,Day,Month,Area,Year) = Electric Load Curve from Demand Sector (MW)
MSF (ECC,Area,Node,ReCo,Year) = Market Share Fraction
TDEF (Fuel,Area,Year) = T&D Efficiency (Btu/Btu)
Key outputs
LDCAr (ECC,Day,Month,Area,ReCo,Year) = Electric Load Curve (MW)
LDCMS (Day,Month,Node,ReCo,Year) = Marketer System Load Curve (MW)
LDCNd (ECC,Day,Month,Node,ReCo,Year) = Electric Load Curve (MW)

Procedure ElectricSales

This procedure calculates the sales from various Loads; node sales (SaECN) from node loads (LDCNd), area sales (SaECA) from area loads (LDCAr), Sales by economic category (SaEC) from node sales, class sales (SaCl) from sales by economic category, and total sales (TSales) from class sales.

While this variable is called SaEC, it is used only in ElectricPrice.src; elsewhere the version used is SAEC as calculated in the sector loads files RLoad.src, CLoad.src, ILoad.src, and TLoad.src. SAEC, SAECA, SACL, and TSales are all used in price calculations in ElectricPrice.src.

Key equations in *ElectricSales* are:

Key Equations:
ElectricSales

Total electricity sales by ECC, retail company, and area:

$$SAECA = \sum_{Month} (LDCAr * Hours)/1000$$

Total electricity sales by ECC, retail company, and node:

$$SAECN = \sum_{Month} (LDCNd * Hours)/1000$$

Total electricity sales by ECC and retail company:

$$SAEC = \sum_{Node} SAECN$$

Total electricity sales by class and retail company:

$$SACL = \sum_{ECC} (SAEC * ECCCLMap)$$

Total electricity sales by retail company:

$\text{TSALES} = \sum_{\text{Class}} \text{SACL}$

Table 4 summarizes the variable names and definitions of the inputs and outputs to *ElectricSales*.

Table 4: Input and Output Variables - ElectricSales

***ElectricSales* Inputs and Outputs**
Key inputs LDCAr (ECC,Day,Month,Area,ReCo,Year) = Electric Load Curve (MW) LDCNd (ECC,Day,Month,Node,ReCo,Year) = Electric Load Curve (MW) **Key outputs** SAEC (ECC,ReCo,Year) = Electricity Sales (GWh/Yr) SAECA (ECC,Area,ReCo,Year) = Electricity Sales (GWh/Yr) SAECN(ECC,Node,ReCo,Year) = Electricity Sales (GWh/Yr) SACL (Class,ReCo,Year) = Electricity Sales (GWh/Yr) TSales (ReCo,Year) = Electricity Sales (GWh/Yr)

Procedure ReCoPeakAverageMinimumLoads

This procedure calculates minimum, average, and peak demand loads (MDP, ADP, PDP) from the marketer system loads (LDCMS). These loads are used in the procedures *ReCoMaximumBaseloadPoint*, *ReCoMaximumIntermediatePoint*, and *PowerFractions*.

Key Equations in *ReCoPeakAverageMinimumLoads* are as follows:

Key Equations: *ReCoPeak Average MinimumLoads*

Annual average load by retail company:

$\text{ADP} = \sum_{\text{Node}}(\text{LDCMS}_{\text{Average}})$

Annual minimum load by retail company:

$\text{MDP} = \sum_{\text{Node}}(\text{LDCMS}_{\text{Minumum}})$

Annual peak load by retail company:

$\text{PDP} = \sum_{\text{Node}}(\text{LDCMS}_{\text{Peak}})$

Table 5 summarizes the names and definitions of the input and output variables to *ReCoPeakAverageMinimumLoads*.

Table 5: Input and Output Variables - ReCoPeakAverageMinimumLoads

***ReCoPeakAverageMinimumLoads* Inputs and Outputs**
Key inputs LDCMS (Day,Month,Node,ReCo,Year) = Marketer System Load Curve (MW) **Key outputs** ADP (Month,ReCo,Year) = Annual Average Load (MW) MDP (Month,ReCo,Year) = Annual Minimum Load (MW) PDP (Month,ReCo,Year) = Annual Peak Load (MW)

Procedure ReCoMaximumBaseloadPoint/ReCoMaximumIntermediatePoint

The maximum baseload point on the LDC (MBP) and maximum intermediate load point on the LDC (MILP) are calculated from the minimum, average, and peak demand loads (MDP, ADP, PDP). MBP and MILP are used in the procedure *PowerFractions*.

Key equations in *ReCoMaximumBaseloadPoint* and *ReCoMaximumIntermediatePoint* are as follows:

Key Equations: *ReCoMaximum BaseloadPoint & ReCoMaximum IntermediatePoint*

Maximum baseload point:

MBP = MDP + (PDP-MDP)*(1-MBD/8760)***max*(0,(PDP-ADP)/(ADP-MDP))

Maximum intermediate load point:

MILP = MDP + (PDP-MDP)*(1-MILD/8760)***max*(0,(PDP-ADP)/(ADP-MDP))

Table 6 summarizes the variable names and definitions of the inputs and outputs to this procedure.

Table 6: Input and Output Variables - ReCoMaximumBaseloadPoint

***ReCoMaximumBaseloadPoint/ReCoMaximumIntermediatePoint* Inputs and Outputs**
Key inputs MDP (Month,ReCo,Year) = Annual Minimum Load (MW) ADP (Month,ReCo,Year) = Annual Average Load (MW) PDP (Month,ReCo,Year) = Annual Peak Load (MW) **Key outputs** MBP (Month,ReCo,Year) = Maximum Baseload Point (MW) MILP (Month,ReCo,Year) = Maximum Intermediate Load Point (MW)

Procedure PowerFractions

This procedure calculates the power type fractions (PwrFra) from the minimum, average, and peak demand loads (MDP, ADP, PDP). These represent the percentage of demand in the peak, intermediate, and minimum sections of the load curve. Power fraction (PwrFra) is used in ECapacityExpansion.src, where they are used to simulate load forecasting in capacity expansion planning.

Key Equations in *PowerFractions* are as follows:

Key Equations:
PowerFractions

<u>*Maximum baseload point:*</u>

$PwrFra = \sum_{Month} (PwrFrAve) / \sum_{Month,Power} (PwrFrAve)$

Where

$PwrFrAve_{Minimum} = \sum (MBP) / (\sum (PDP)$

$PwrFrAve_{Intermediate} = \sum (MILP\text{-}MBP) / \sum (PDP)$

$PwrFrAve_{Peak} = \sum (PDP\text{-}MILP) / (\sum (PDP)$

Table 7 summarizes the variable names and definitions of the key inputs and outputs to the PowerFractions procedure.

Table 7: Input and Output Variables - PowerFractions

***PowerFractions* Inputs and Outputs**
Key inputs ADP (Month,ReCo,Year) = Annual Average Load (MW) PDP (Month,ReCo,Year) = Annual Peak Load (MW) MBP(Month,ReCo,Year) = Maximum Baseload Point on Load Duration Curve (MW) MDP (Month,ReCo,Year) = Annual Minimum Load (MW) MILP(Month,ReCo,Year) = Maximum Base Load Power (MW) **Key output** PwrFra (Power,GenCo,Year) = Maximum Baseload Point (MW)

Procedure SystemAnnualPeakAverageMinimumLoads

This procedure calculates the system annual loads (LDCSA) – that is, the highest peak loads from the entire year, lowest minimum loads from the entire year, and the mean average load across the months of the year – from the retail loads (MDP, ADP, PDP). The system annual loads are used in contract development for determining self-dealing fractions.

Key Equations in *SystemAnnualPeakAverageMinimumLoads* are as follows:

Key Equations: *SystemAnnual PeakAverage MinimumLoads*

Annual system minimum load:

$LDCSA_{Minimum} = min_{Month}$ (MDP)

Annual system average load:

$LDCSA_{Average} = \sum_{Month}$ (ADP*Hours) / $\sum_{Month}$ (Hours)

Annual system peak load:

$LDCSA_{Peak} = max_{Month}$ (PDP)

Table 8 summarizes the variable names and definitions of the procedures' key inputs and outputs.

Table 8: Input and Output Variables - SystemAnnualPeakAverageMinimumLoads

***SystemAnnualPeakAverageMinimumLoads* Inputs and Outputs**
Key inputs MDP (Month,ReCo,Year) = Annual Minimum Load (MW) ADP (Month,ReCo,Year) = Annual Average Load (MW) PDP (Month,ReCo,Year) = Annual Peak Load (MW) **Key output** LDCSA (Day,ReCo,Year) = Annual System Load Curve (MW)

Procedure LoadsInTimeIntervals

This procedure converts peak, average, and minimum loads into a load curve by six time periods, which, after adjusting for cogeneration in a later procedure, will be used to determine the loads and energy requirements for the generation dispatch submodule.

A load curve is fitted to the peak, average, and minimum points on the marketer loads. These three points represent the peak, average, and minimum hours for each month, node, and retail company. Note that the definition of "month" can vary by model version – some versions have a 12-month representation, and others have a 2-season representation. The current standard version of the model (as of June 2017) uses a 2-season representation (winter and summer) for month. The load curve is fitted by interpolating the three day values—the peak, average, and minimum hours for each month – into a representative six time periods for each month/season. We do this rather than representing each of 8760 hours as a simplification and due to lack of sufficiently detailed data for the load shape behavior of detailed enduses in the demand sector.

From this load curve, we calculate the peak demand (HMPDP), average demand (HMADP), and total energy requirements (HMEnergy) for each of six time periods. The six time periods are peak, near peak, high intermediate, low intermediate, high base load, and low base load. After being adjusted for cogeneration in the procedure *HourlyLoads*, these procedures will be used in the generation dispatch submodule.

The key equations in *LoadsInTimeIntervals* are as follows:

Key Equations: ***LoadsIn TimeIntervals***

<u>*System peak load in interval, with cogeneration:*</u>

$HMPDP = LDCMS_{Minimum}+(LDCMS_{Peak}-LDCMS_{Minimum})*(1-HDHrPk/Hours)**(LDCMS_{Peak}-LDCMS_{Average})/(LDCMS_{Average}-LDCMS_{Minimum})$

<u>*System energy in interval, with cogeneration:*</u>

$HMEnergy=HMEnergy_{Unadjusted} *(LDCMS_{Average}*Hours/1000)/\sum(HMEnergy_{Unadjusted})$

a. $HMEnergy_{Unadjusted} = (HMMDP*HDHours/1000)+max((HMEGPk-HMEGMn)-(HMPDP-HMMDP)*HDHrPk/1000,0)$
b. $HMMDP=LDCMS_{Min}+(LDCMS_{Peak}-LDCMS_{Min})*(1-HDHrMn/Hours)**(LDCMS_{Peak}-LDCMS_{Average})/(LDCMS_{Average}-LDCMS_{Minimum})$
c. $HMPDP=LDCMS_{Min}+(LDCMS_{Peak}-LDCMS_{Min})*(1-HDHrPk/HOURS)**LDCMS_{Peak}-LDCMS_{Average})/(LDCMS_{Average}-LDCMS_{Minimum})$
d. $HMEGMn=Hours/1000*(HMMDP)$
e. $HMEGPk=Hours/1000*(HMPDP)$

<u>*System average load in interval, with cogeneration:*</u>

$HMADP = HMEnergy/HDHours*1000$

Table 9Table 9 summarizes the key input and output variables in the LoadsInTimeIntervals procedure.

Table 9: Input and Output Variables - LoadsInTimeIntervals

***LoadsInTimeIntervals* Inputs and Outputs**
Key inputs LDCMS (Day,Month,Node,ReCo,Year) = Marketer System Load Curve (MW) **Key outputs** HMADP (Node,ReCo,TimeP,Month,Year) = Average Load in Interval (MW) HMPDP (Node,ReCo,TimeP,Month,Year) = Peak Load in Interval (MW) HMEnergy (Node,TimeP,Month,Year) = Energy In Interval (GWH)

Procedure HourlyLoads

This procedure adjusts the interval loads (HMPDP, HMADP) and energy requirements (HMEnergy) of *LoadsPerInterval* by incorporating into them cogeneration via power sold to grid (PSoECC). It creates the hourly loads and energy requirements (HDPDP, HDADP, and HDEnergy) with the energy and peak power sold to grid (PSoEnergy, PSoPDP).

The hourly loads and energy requirements (HDPDP, HDADP, and HDEnergy) are used in EDispatch.src. The energy requirements are also used in the fuel usage submodule.

Note: The Peak Power Sold to Grid is currently zero because of an input without values, the Power Sold to Grid Load Shape Factors (PSoLSF). The new variable, CgLSF might be more accurate.

The key equations in *HourlyLoads* are as follows:

Key Equations: *HourlyLoads*

Energy in interval, without cogeneration:

HDEnergy = $\sum_{ReCo}$ (HMEnergy)-PSoEnergy

Average load in interval, without cogeneration:

HDADP = HDEnergy/HDHours*1000

Peak load in interval, without cogeneration:

HDPDP = $\sum_{ReCo}$ (HMPDP)-PSoPDP

Where: PSoPDP=(PSoECC*ArNdFr*PSoLSF)/8760*1000

Table 10Table 10 below shows the key input and output variables for the procedure *HourlyLoads*.

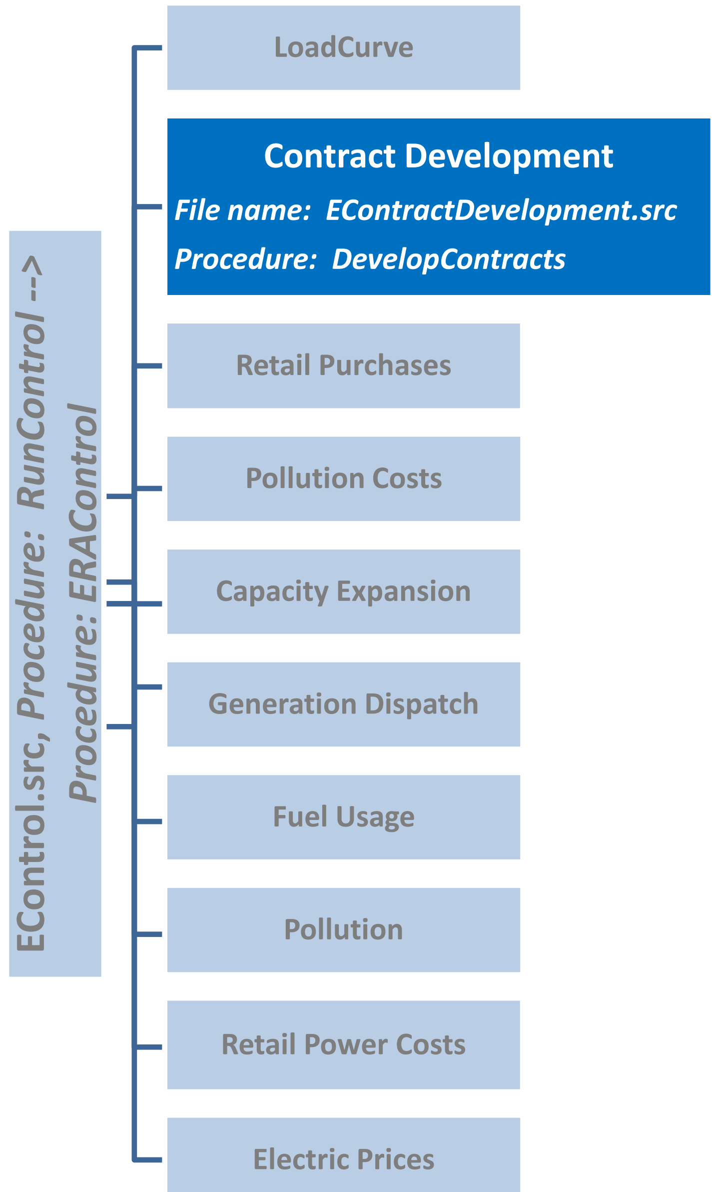
Table 10: Input and Output Variables - HourlyLoads

***HourlyLoads* Inputs and Outputs**
Key inputs HMPDP (Node,ReCo,TimeP,Month,Year) = Peak Load in Interval (MW) HMEnergy (Node,TimeP,Month,Year) = Energy In Interval (GWh) PSoECC(ECC,Area,Year) = Power Sold to Grid (GWh) PSoLSF(ECC,Area,TimeP,Month,Year) = Load Shape Factor for Power Sold to Grid (MW/MW) **Key outputs** HDADP (Node,TimeP,Month,Year) = Average Load in Interval (MW) HDPDP (Node,TimeP,Month,Year) = Peak Load in Interval (MW) HDEnergy (Node,TimeP,Month,Year) = Energy In Interval (GWh)

3. Contract Development Submodule

EContractDevelopment.src contains the source code and procedures that make up the retail and generating company contract development submodule. The contract development submodule's main procedure is named *DevelopContracts*. The call to *DevelopContracts* is initiated in the *RunControl* procedure inside *EControl.src* by calling procedure *ERAControl* which then in turn calls *DevelopContracts*. The contract development submodule is executed directly after the load curves have been calculated in the load curve submodule.

Figure 10: Contract Development in Electric Supply



Submodule Objective

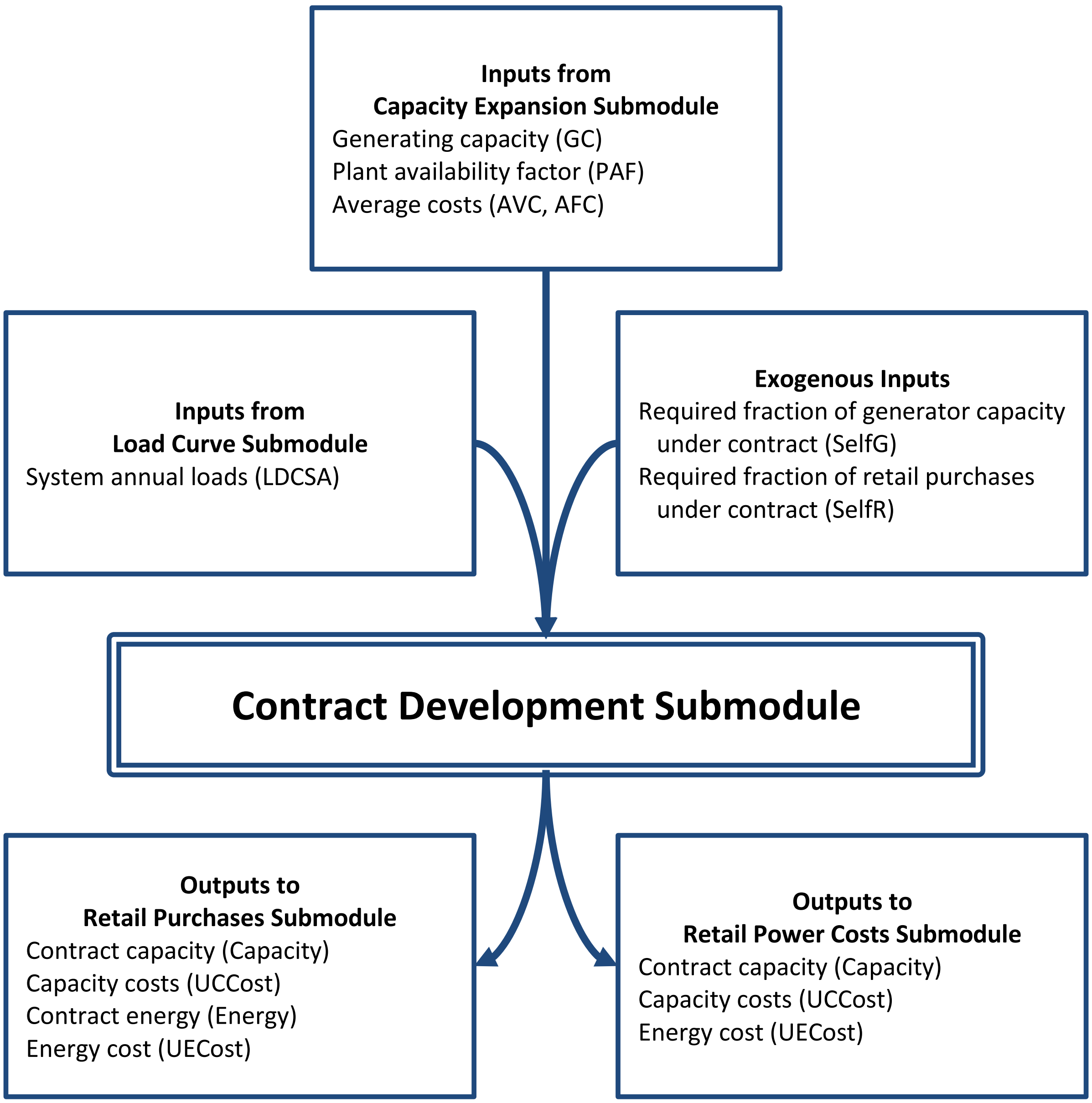
All electric power generated by utilities is sold to retail companies, who have sales to demand areas and a retail cost structure. Retail companies can choose to fulfill the needs of their customers either through contracts made with a specific generating company or by purchasing wholesale power from the market. A contract is a pre-determined purchase agreement between the generating company and retail company. The contract development submodule creates the parameters necessary to simulate the flow of power from generating companies to the customer.

Currently, ENERGY 2020 splits up the simulation of retail companies into several different submodules (contract development, retail purchases, and retail power costs), each reflecting a different stage of the development of retail company costs and finances. The purpose of the contract development submodule is to set up the specifications of potential retail company contracts with generating companies. The specifications include minimum and maximum amounts of capacity to be purchased by each retail company, the energy available for each contract, and the cost of capacity and energy purchased through contracts. These contract specifications will be used as input to the retail purchases submodule.

Submodule Methodology

The contract development submodule uses capacity (GC), plant capacity factors (PCF), and average variable and fixed cost (AFC,AVC) inputs to develop contract costs (UECost,UCCost), capacity (Capacity), and generation (Energy) that are used to dispatch contracts in retail purchases. The submodule first calculates the cost of endogenous contracts using other inputs from the electric sector and then adds in any exogenously defined contracts. Figure 11 illustrates the key inputs and outputs of the contract development submodule.

Figure 11: Contract Development Submodule - Inputs and Outputs



Submodule Procedures

The procedures that make up the contract development submodule are shown in Figure 12 below. These are all housed in EContractDevelopment.src and called from the *DevelopContracts* procedure.

Figure 12: Procedure DevelopContracts in EContractDevelopment.src

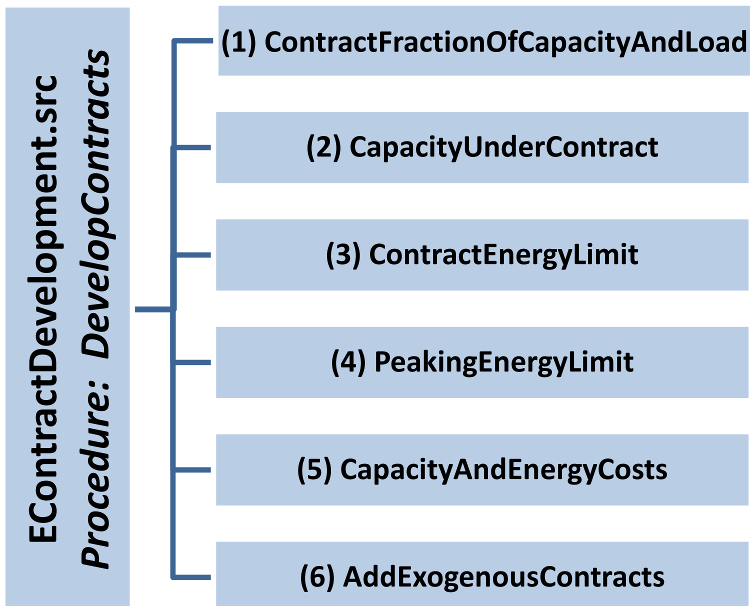


Table 11 provides a brief description of each of contract development procedures and identifies the key output variables. More detailed descriptions of these procedures are provided in the sections following the table.

Table 11: Description of Contract Development Procedures

Procedure Description	Key Outputs
1. ContractFractionOfCapacityAndLoad This procedure determines how much power a retail company will get from contracts with generating companies as a self-dealing fraction (SelfFr). The self-dealing fraction is based on two exogenously-specified variables, therefore allows the user to determine to what extent the retail company utilizes the spot market versus bilateral contracts.	Self-dealing fraction (SelfFr)

Procedure Description	Key Outputs
2. CapacityUnderContract This procedure applies the self-dealing fraction (SelfFr) determined in *ContractFractionOfCapacityAndLoad* to capacity (GC) to calculate the amount of capacity under contract (Capacity).	Capacity under contract (Capacity)
3. ContractEnergyLimit The amount of energy available for each contract (Energy) is determined by applying a plant capacity factor (PCF) to capacity under contract (Capacity).	Energy available by contract (Energy)
4. PeakingEnergyLimit The amount of energy available for contracts with peaking plants ($Energy_{Peaking}$) is determined based on the plant availability factor (PAF) rather than the plant capacity factor (PCF) used in *ContractEnergyLimit*.	Energy available for contracts for peaking plants ($Energy_{Peaking}$)
5. CapacityAndEnergyCosts Calculates the capacity and energy costs (UCCost, UECost) of the contracts. The costs are based on the generating companies' average fixed costs (AFC) and average variable costs (AVC).	Contract capacity and energy costs (UCCost,UECost)
6. AddExogenousContracts *AddExogenousContracts* allows for the user to use either exogenously specified contract costs (XCapSw = 1) or endogenous costs (XCapSw = 2).	Contract capacity and energy costs (UCCost,UECost)

Procedure ContractFractionOfCapacityAndLoad

The electric market in each area modeled can contain a variety of different regulations, including whether electricity is sold exclusively through contracts, through the spot-market, or a combination of both. Each regulatory approach can result in significant difference in the final retail price, so ENERGY 2020 requires the market-type as an input to the model. This procedure determines a retail company self-dealing fraction (SelfFr), which is the fraction of power that will be purchased through a contract with a generating company. This fraction is set either by a requirement to purchase power from a specific generating company (SelfG) or the fraction of the retail company peak for which they sign a bilateral contract with the generator (SelfR). Both variables are exogenous inputs to the model, meaning that the requirement can be customized by the user. This procedure allows the user to determine to what extent the retail company utilizes the spot market versus bilateral contracts.

The equations used to create the self-dealing fraction (SelfFr) are listed below.

Key Equations: *ContractFraction OfCapacity AndLoad*

<u>*Self-dealing fraction:*</u>

SelfFr=SelfCap/GC

Where SelfCap=Maximum (GC*SelfG, Minimum ($LDCSa_{Peak}$*SelfR, GC))

Table 12 summarizes the variables names and descriptions of the inputs and outputs to *ContractFractionOfCapacityAndLoad*.

Table 12: Input and Output Variables - ContractFractionOfCapacityAndLoad

***ContractFractionOfCapacityAndLoad* Inputs and Outputs**
Key inputs GC (Plant,Node,GenCo,Year) = Generation Capacity (MW) SelfG (ReCo,GenCo,Year) = Minimum Fraction of GenCo Capacity Purchased by ReCo (MW/MW) SelfR (ReCo,GenCo,Year) = Minimum Fraction of ReCo Load Purchased from GenCo (MW/MW) **Key output** SelfFr (ReCo,GenCo,Year) = Self-Dealing Fraction as Output (MW/MW)

Procedure CapacityUnderContract

With the market type determined, the amount of capacity available for contracts between the generating and retail companies can be set. The amount of generating capacity under contract (Capacity) between a retail company and generating company for each plant type, time period, and month is the capacity available for each generating company (GC) times the self-dealing fraction (SelfFr). This procedure calculates the capacity under contract (Capacity) which is then used as input to the retail purchases submodule. If the electric market is determined to be entirely driven by the spot market (SelfFr = 0), then the available capacity for contracts will be zero.

The key equation used in the *CapacityUnderContract* is:

Key Equation: *CapacityUnder Contract*

<u>*Capacity under contract:*</u>

Capacity=GC*SelfFr

Table 13 summarizes the key input and output variables from *CapacityUnderContract*.

Table 13: Input and Output Variables - CapacityUnderContract

***CapacityUnderContract* Inputs and Outputs**
Key inputs GC (Plant,Node,GenCo,Year) = Generation Capacity (MW) SelfFr (ReCo,GenCo,Year) = Self-Dealing Fraction as Output (MW/MW) **Key output** Capacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Capacity under Contract (MW)

Procedure ContractEnergyLimit

For most plant types, the amount of power available for each contract (Energy) is the capacity under contract (Capacity) times the capacity factor for each plant type for the generating company (PCF). The energy available for the contracts (Energy) is calculated in this procedure and used as input to the retail purchases submodule which determines the amount of energy that will ultimately be dispatched.

Key Equation: *ContractEnergy Limit*

Energy available for contracts:

Energy=∑ (Capacity*PCF*HDHours)/1000

Table 14 summarizes the key input and output variables to *ContractEnergyLimit*.

Table 14: Input and Output Variables - ContractEnergyLimit

***ContractEnergyLimit* Inputs and Outputs**
Key inputs Capacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Capacity under Contract (MW) PCF (Plant,GenCo,Year) = Plant Capacity Factor (MW/MW) **Key outputs** Energy (ReCo,GenCo,Plant,Year) = Energy Limit on Contracts (GWh/Yr)

Procedure PeakingEnergyLimit

Gas turbine and other types of peaking plants operate sporadically, so using the capacity factor to determine the energy limit can be misleading. The amount of energy available for contracts with peaking plants ($\text{Energy}_{\text{Peaking}}$) is determined based on the plant availability factor (PAF) rather than the plant capacity factor (PCF) used in *ContractEnergyLimit*.

The equation used to calculate the energy available for peaking plants is listed below.

Key Equation: *PeakingEnergy Limit*

Energy available for contracts:

Energy=∑ (Capacity*PAF*HDHours)/1000

Table 15 summarizes the variable names and definitions of the key inputs and outputs to this procedure.

Table 15: Input and Output Variables - PeakingEnergyLimit

***PeakingEnergyLimit* Inputs and Outputs**
Key inputs Capacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Capacity under Contract (MW) PAF (Plant,GenCo,Year) = Plant Availability Factor (MW/MW) **Key outputs** Energy (ReCo,GenCo,Plant,Year) = Energy Limit on Contracts (GWh/Yr)

Procedure CapacityAndEnergyCosts

The purpose of the CapacityAndEnergyCosts procedure is to calculate the cost of capacity and energy for the contracts. The capacity costs for the contract (UCCost) for each plant type are the average fixed costs for each generating company (AFC). The cost of purchasing energy for each contract (UECost) is the average variable costs for each generating company (AVC). The costs are sent to the Retail Purchases Submodule to determine the lowest cost options for dispatching contracts.

Key Equations: *CapacityAnd EnergyCosts*

Contract capacity cost:

UCCost=AFC*AFCM

Contract energy cost:

UECost=AVC

Table 16 summarizes the variable names and definitions of the input and outputs from *CapacityAndEnergyCosts*.

Table 16: Input and Output Variables - CapacityAndEnergyCosts

***CapacityAndEnergyCosts* Inputs and Outputs**
Key inputs AFC (Plant,GenCo,Year) = Average Fixed Costs ($/KW) AVC (Plant,GenCo,Year) = Average Variable Costs ($/MWh)

CapacityAndEnergyCosts Inputs and Outputs
Key outputs UCCost (ReCo,GenCo,Plant,Year) = Contract Capacity Cost ($/KW) UECost (ReCo,GenCo,Plant,Year) = Contract Energy Cost ($/MWh)

Procedure AddExogenousContracts

Depending on the type of analysis being performed, often the user will want specific predetermined contracts used for simulation instead of the endogenously created values. The code in this procedure allows the user to directly set up a contract between generating and retail companies and read in the capacity, energy, and cost parameters. Exogenous contracts are typically read into the model via text files in *2020Model*, where the user specifies the parameters of the contract, including the contract capacity and costs. *AddExogenousContracts* allows for the user to use either exogenously specified contract costs (XCapSw = 1) or endogenous costs (XCapSw = 2).

Table 17 summarizes the variable names and definitions of the key inputs and outputs to this procedure.

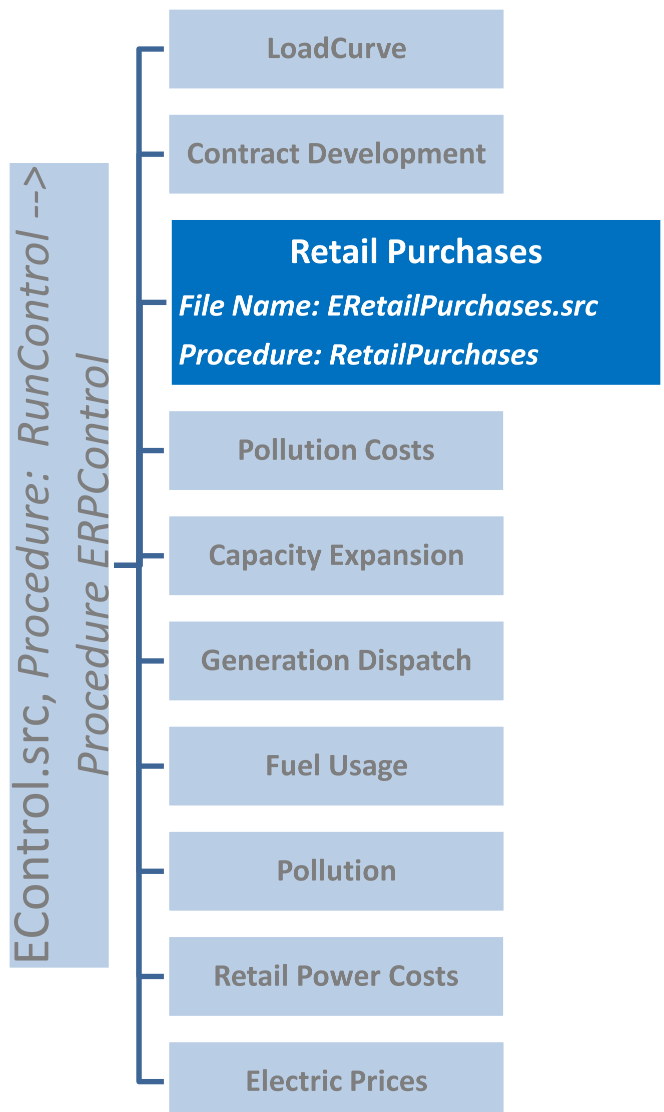
Table 17: Input and Output Variables - AddExogenousContracts

AddExogenousContracts Inputs and Outputs
Key inputs XCapSw (ReCo,GenCo,Plant,Year)= Switch for Exogenous Contracts XCapacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Exogenous Capacity under Contract (MW) XUCCost (ReCo,GenCo,Plant,Year) = Exogenous Contract Capacity Cost ($/KW) XUECost (ReCo,GenCo,Plant,Year) = Exogenous Contract Energy Cost ($/MWh) **Key outputs** UCCost ReCo,GenCo,Plant,Year = Contract Capacity Cost ($/KW) UECost ReCo,GenCo,Plant,Year = Contract Energy Cost ($/MWh) Energy ReCo,GenCo,Plant,Year = Energy Limit on Contracts (GWh/Yr) Capacity ReCo,GenCo,Plant,TimeP,Month,Year = Capacity under Contract (MW)

4. Retail Purchases Submodule

The *ERetailPurchases.src* file contains the source code and procedures that make up the retail purchases submodule. Its main procedure is named *Retail Purchases* and is called from the *RunControl* procedure inside *EControl.src* which calls ERPControl which ultimately calls *RetailPurchases.* At the point when the retail purchases submodule is called, the load curves have been created and purchase power contracts have been developed but not dispatched.

Figure 13: Retail Purchases in Electric Supply



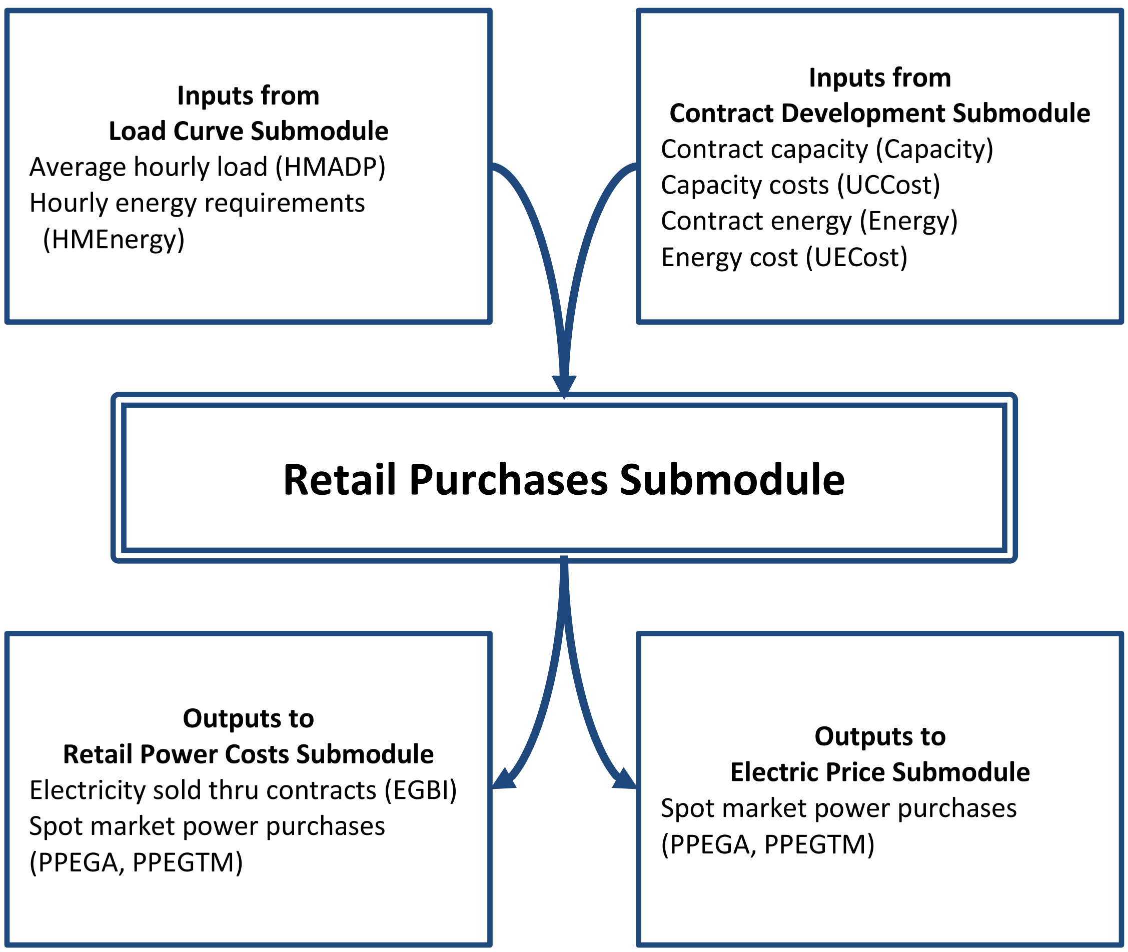
Submodule Objective

With the contract costs (UECost, UCCost), capacity (Capacity), and energy limits (Energy) set between each generating and retail company the model is now ready to create contracts to meet electric demands. In this section, retail companies have the option to purchase electricity either from contracts with generating companies or through the spot market dependent on the regulatory system in place for each market. The retail and generating companies create contracts until either all demands have been met or all energy available for contracts has been exhausted. If the latter occurs, then the retail company meets the remaining demand by purchasing from the spot market. The key output for this procedure are the amount of generation coming from either contracts (EGBI) or from the spot market (PPEGA).

Submodule Methodology

Contracts for each retail company are dispatched starting with the lowest cost contracts (which are developed in the contract development submodule) until all energy needs are met or there are no more available contracts in which case energy needs are met through electricity purchases from the spot market. The amount of electricity purchased from contracts (EGBI) and the spot market (PPEGA) are output for use in calculating retail power costs and the final electric price.   Figure 14 provides a diagram of the key inputs to and outputs from the retail purchases submodule.

Figure 14. Retail Purchases Submodule Diagram of Inputs and Outputs



Submodule Procedures

Figure 15 below lists each of the procedures that make up *RetailPurchases* and shows the order of procedures called.

Figure 15: Procedure RetailPurchases in ERetailPurchases.src

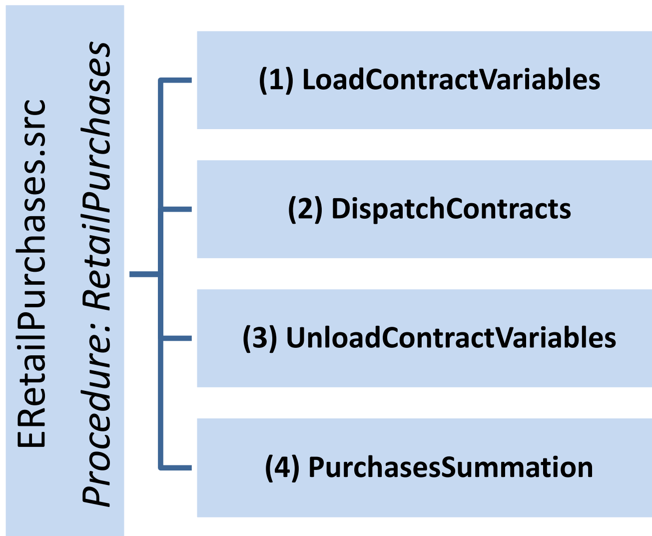


Table 18 describes each procedure within the retail purchases submodule along with its key outputs. The sections that follow provide more detailed descriptions of the methodology within the procedure.

Table 18: Description of Retail Purchases Procedures

Procedure Description	Key Outputs
1. LoadContractVariables Set the capacity, amount of energy, and cost of each contract.	Contract costs and energy usage (CnEnergy, CnUECost)
2. DispatchContracts Dispatch contract generation starting with the lowest cost contracts. If power needed exceeds power available through contracts then purchase from the spot market.	Contract generation (CnEG)

Procedure Description	Key Outputs
3. UnloadContractVariables Save total contract values for contracts and spot markets.	Electric sold through contracts(EGBITM) and spot market purchases (PPEGTM) by month and time period
4. PurchasesSummation This procedure aggregates output from procedures above into variables used by other areas of the model. The inputs are electricity sold through contracts (EGBITM) and spot market purchases (PPEGTM) each by month and time period. The saves new variables that are totaled across month and time period for electricity sold through contracts and spot market purchases (EGBI and PPEGA). Electricity sold through contracts is further summed across generating company to get total electricity sold through contracts for each retail company (EGA).	Electricity sold through contracts (EGBI); Electricity dispatched (EGA); spot market purchases (PPEGA)

Procedure LoadContractVariables

This section of code is designed to cycle through each combination of Generating and Retail Company for each plant type, month, and time interval to determine if capacity for a contract is above zero (Capacity). If so, a contract between retail and generator is created (CreateContract). Contract costs, energy limits, capacity, and other characteristics are saved for use in dispatching contracts. After a contract is created the model moves to the next contract slot (CnNumber) until every generating company has been checked. After all contracts have been created then parameters for the spot market for each retail company are saved. Capacity for the spot market is set equal to the peak load for each retail company (HMPDP) and the energy limit equal to the total energy available (HMEnergy). Other parameters are set equal to '99' to identify it as the spot market.

Table 19 summarizes the variable names and definitions of the key inputs and outputs to *LoadContractVariables*.

Table 19: Input and Output Variables - LoadContractVariables

***LoadContractVariables* Inputs and Outputs**
Key inputs Capacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Capacity under Contract (MW) Energy (ReCo,GenCo,Plant,Year) = Energy Limit on Contracts (GWh/YR) UECost (ReCo,GenCo,Plant,Year) = Contract Energy Cost ($/MWh) HMADP(Node,ReCo,TimeP,Month,Year) = Average Load in Interval (MW) **Key outputs** CnCap (Contracts,ReCo,TimeP,Month) = Contract Capacity (MW) CnEnergy(Contracts,ReCo,TimeP,Month) = Contract Energy (GWH) CnUECost(Contracts,ReCo,TimeP,Month)= Contract Energy Cost ($/MWH) Capacity (ReCo,GenCo,Plant,TimeP,Month,Year) = Capacity under Contract (MW)

Procedure DispatchContracts

With the contracts and spot market for each retail company created, the model is ready to dispatch to meet electric demand. Demand needed to be met by each retail company (HMPDPM) is set equal to the average load (HMADP). Starting with the least expensive contract, demand met by each contract (CnMDS) is calculated as either the maximum capacity, energy limit of the contract, or remaining demand requirements (HMPDPDM). Demand met by the contract is then subtracted from demand requirements before moving to the next contract. Total generation for each contract (CnEG) is the demand met by each contract (CnMDS) multiplied by the amount of hours in each time interval (HDHours).

The equations used to create the contract generation (CnEG) are listed below.

Key Equations: *Dispatch Contracts*

<u>*Contract generation:*</u>

1) CnEG=CnMDS*HDHours/1000

Where, CnMDS = Minimum (CnCap, HMADP, CnEnergy/HDHours*1000)

Table 20 summarizes the variable names and definitions of the key inputs and outputs to the *DispatchContracts* procedure.

Table 20: Input and Output Variables - DispatchContracts

***DispatchContracts* Inputs and Outputs**
Key inputs CnCap (Contracts,ReCo,TimeP,Month) = Contract Capacity (MW) CnEnergy (Contracts,ReCo,TimeP,Month)= Contract Energy (GWh) CnUECost(Contracts,ReCo,TimeP,Month)= Contract Energy Cost ($/MWH) HMADP (Node,ReCo,TimeP,Month,Year) =Average Load in Interval (MW)

DispatchContracts Inputs and Outputs
Key outputs CnEG(Contracts,ReCo,TimeP,Month) = Contract Generation (GWh)

Procedure UnloadContractVariables

This procedure checks to see if generation (CnEG) is coming from a contract or the spot market. If generation is from a contract the amount of generation (EGBI) is saved to determine the cost of electricity in other parts of the model. If generation is from the spot market the amount of generation (PPEGA) is saved.

Key Equations: *Unload ContractVariables*

Electricity sold through contracts:

EGBITM=CnEG

Power purchases:

PPEGTM=CnEG

Table 21 summarizes the variable names and definitions of the key inputs and outputs to the *UnloadContractVariables* procedure.

Table 21: Input and Output Variables - UnloadContractVariables

UnloadContractVariables Inputs and Outputs
Key inputs CnEG(Contracts,ReCo,TimeP,Month) = Contract Generation (GWh) CnGenCo (Contracts,ReCo,TimeP,Month) = Contract GenCo
Key outputs EGBITM(ReCo,GenCo,Plant,TimeP,Month,Year) = Electricity sold thru Contracts (GWh/YR) PPEGTM(ReCo,TimeP,Month,Year) = Power Purchases (GWh)

Procedure PurchasesSummation

This procedure aggregates output from procedures above into variables used by other areas of the model. The inputs are electricity sold through contracts (EGBITM) and spot market purchases (PPEGTM) each by month and time period. The saves new variables that are totaled across month and time period for electricity sold through contracts and spot market purchases (EGBI and PPEGA). Electricity sold through contracts is further summed across generating company to get total electricity sold through contracts for each retail company (EGA).

The key equations used in the PurchasesSummation procedure are as follows:

Key Equations:
Purchases Summation

Electricity sold through contracts by plant type, retail company, generating company:

$EGBI=\sum_{TimeP,\ Month} EGBITM$

Electricity sold through contracts by plant and retail company:

$EGA = \sum_{GenCo} EGBI$

Power purchases through spot market:

$PPEGA =\sum_{TimeP,\ Month} PPEGTM$

$TPPEGA = =\sum_{Power\ types} PPEGA$

Table 22 summarizes the variable names and definitions of the key inputs to and outputs from *PurchasesSummation*.

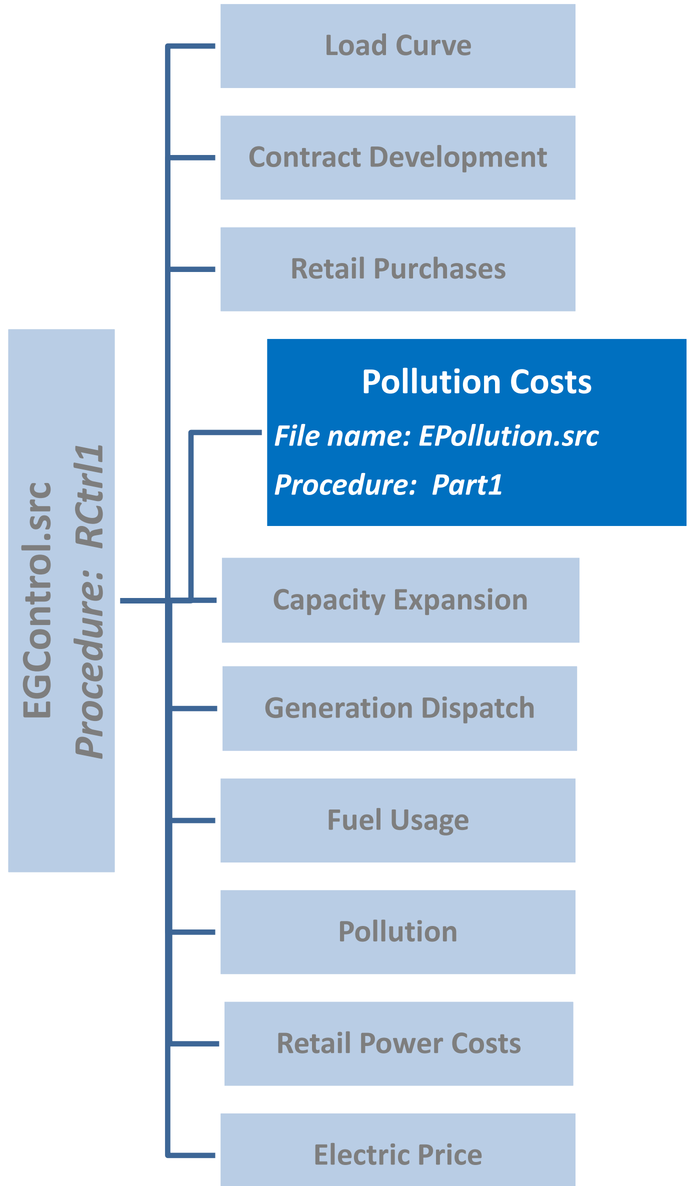
Table 22: Input and Output Variables - PurchasesSummation

PurchasesSummation **Inputs and Outputs**
Key inputs EGBITM(ReCo,GenCo,Plant,TimeP,Month,Year) = Electricity sold thru Contracts (GWh/YR) PPEGTM(ReCo,TimeP,Month,Year) = Power Purchases (GWh) **Key outputs** EGBI(ReCo,GenCo,Plant,Year) = Electricity sold thru Contracts (GWh/YR) EGA(Plant, ReCo,Year) = Electricity Dispatched (GWh/Yr) PPEGA(PPSet, ReCo,Year) = Spot Market Purchases (GWh) TPPEGA(ReCo,Year) = Total Purchase Power (GWh)

5. Pollution Costs Submodule

EPollution.src contains the source code and procedures that make up the pollution submodule. The pollution cost submodule's main procedure is named *Part1* and is called from the *RCtrl1* procedure inside EGControl.src. It is called after load curve, contract development, and retail purchases submodules have been executed.

Figure 16: Pollution Costs in Electric Supply



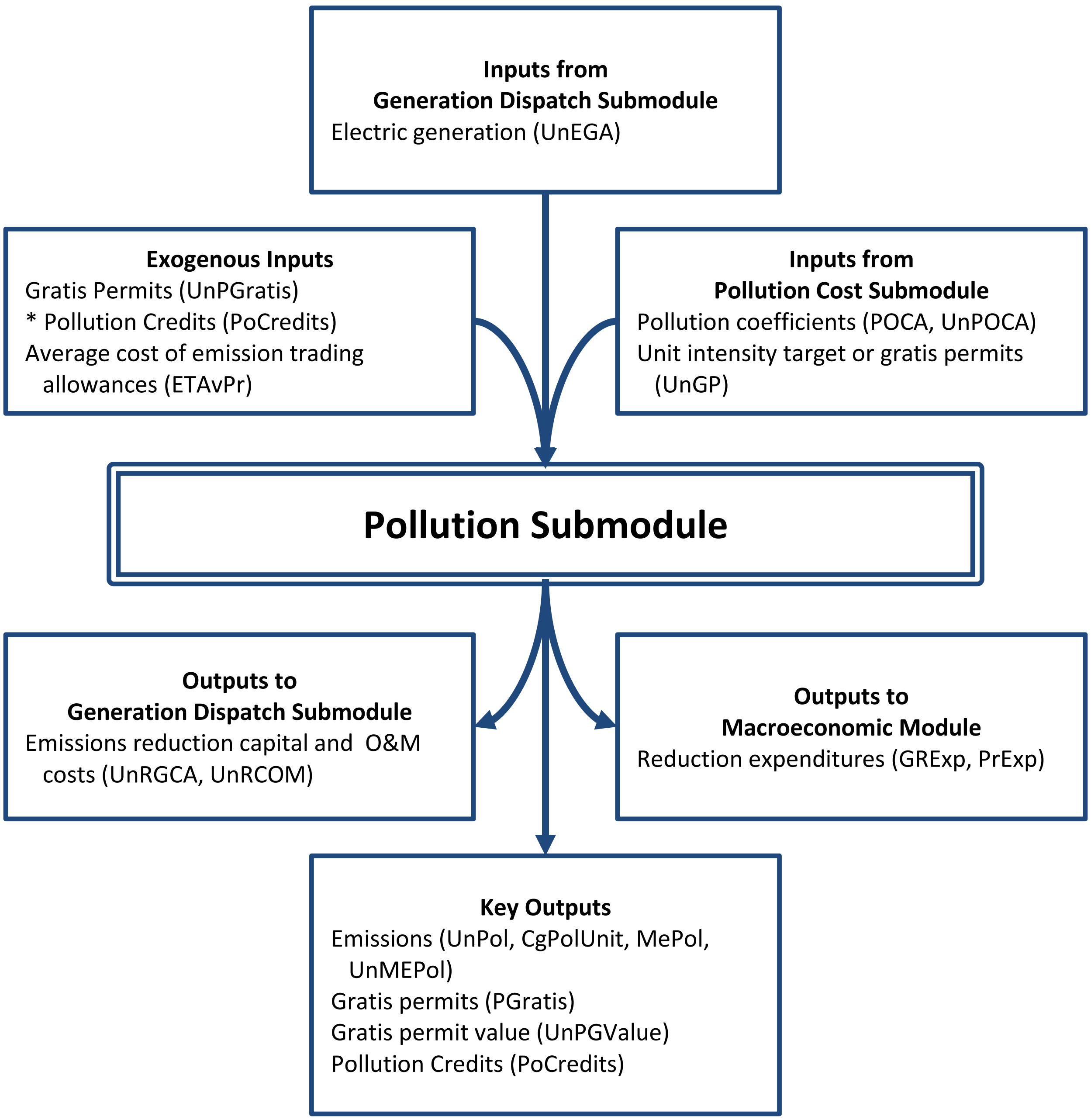
Submodule Objective

The pollution costs submodule determines the amount of emissions reduction required for the utility generation sector from emission reduction policies and applies reductions at the individual unit level. Marginal and average emissions coefficients are recalculated along with an estimation of the costs of the reduction based on abatement curves. The submodule is designed to be robust and offers the user different options to determine how reductions for each unit are calculated.

Submodule Methodology

Plant-type and unit-level emissions reductions and reduction capital costs are calculated. These are then used to adjust pollution coefficients and together they are used to determine the impact of emissions reductions on the price of electricity. Key inputs to *Part1* include the reduction required (RPolicy) or pollution costs (PCostECC), cost curve parameters (EUPCostN, EUPVF), and policy specified model switches to determine the Submodule Methodology (UnPRSw, CapTrade). Key outputs include emission coefficients (POCX, UnPOCX), and reduction costs (UnPoTR). Figure 17 illustrates the key inputs and outputs of the pollution submodule.

Figure 17. Pollution Submodule Diagram of Inputs and Outputs



Submodule Procedures

The main procedures called from the *Part1* procedure in EPollution.src are shown in Figure 18 below.

Figure 18: Procedure Part1 in EPollution.src

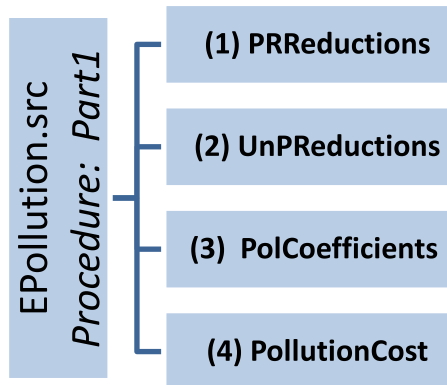


Table 23 describes each of the pollution costs procedures and provides the output variables from each procedure. The subsequent sections provide more detailed descriptions of the methodology within each of the pollution procedures.

Table 23: Description of Pollution Costs Procedures

Procedure Description	Key Outputs
1. PRReductions Calculates the reductions required and marginal reduction costs at the sector level based on emissions caps or other emissions policies.	Reduction requirements (EURM,EURP) and marginal cost (EURCC)
2. UnPReductions Unit-level emissions reduction requirements and marginal cost.	Reduction requirements (UnRM,UnRP) and marginal cost (UnRCC)
3. PolCoefficients Calculates the average emissions coefficient	Average emitted per unit of energy (POCA, UnPOCA)
4. PollutionCosts Creates marginal and average cost of emitting per megawatt hour based on average emissions coefficient	Marginal and average pollution tax rates (UnPoTxR, UnPoTAv)

Procedure PRReductions

The *PRReductions* procedure determines the amount of emissions reductions required for the utility sector; there are two main ways emissions reductions are calculated. The method of reduction for the utility sector is dependent on the value of a policy switch (CapTrade) allowing the user to specify the method of reduction to be simulated. Either the cost of purchasing emissions permits or an emissions cap to meet an emission reduction policy will be specified by the policy. If the cost is specified, the cost of emissions (EURCC) reduction will be used along with abatement curve parameters (EUPCostN, EUPVF) to calculate a percentage reduction (EURP). If the reduction is specified, the intended percentage reductions (EURP) will be used with abatement curve parameters to calculate a cost of reduction (EURCC). The pollution reduction curve is simply the relationship between the cost of reductions and the amount of reductions.

Policies from different years may use different parameters and slightly different formulas, based on a switch (EURPCSw). Most CAC policies are able to use this generic emissions policy logic. Some cap and trade policies may work in a different manner and for such policies, the reductions and reduction capital costs from this procedure may be treated as zero.

Once a reduction and a cost have been determined, these are used to create an emissions reduction multiplier. EURM is the multiplier to the total in order to create the desired percentage reduction (EURP), but also incorporating any voluntary reductions (EUVR) and exogenously specified reductions (XEURM).

PRReductions Inputs and Outputs
Key Inputs
CapTrade (Market,Year) = Emission Cap and Trading Switch
EUPCostN (FuelEP,Plant,Poll,Area,Year) = Pollution Reduction Cost Normal ($/Tonnes)
EUPVF (FuelEP,Plant,Poll,Area,Year) = Pollution Reduction Variance Factor (($/Tonnes)/($/Tonnes))
EURCD (Poll) = Reduction Capital Construction Delay (Years)
EURCPL (Poll) = Reduction Capital Physical Life (Years)
PCost (FuelEP,Plant,Poll,Area,Year) = Permit Cost ($/Tonnes)
RPolicy (ECC,Poll,Area,Year) = Pollution Reduction from Limit (Tonnes/Tonnes)
Key outputs
EURCC (FuelEP,Plant,Poll,Area,Year) = Reduction Capital Cost ($/Tonnes)
EURM (FuelEP,Plant,Poll,Area,Year) = Reduction Multiplier by Area (Tonnes/Tonnes)
EURP (FuelEP,Plant,Poll,Area,Year) = Pollutant Reduction (Tonnes/Tonnes)

Key equations for the plant-type reductions in procedure *PRReductions* include:

Key Equations: *PRReductions*

Reduction capital cost and pollutant reduction factor for policies where costs are specified first:

EURCC = (PCost*ECoverage+PCostExo)/(EUCCR+EUROCF)*Infla

EURP = EURP + (Maximum(EURP,EUIRP)-EURP)/EURCD-EURP/EURCPL

Actual Reductions (EURP) are increased by changes in Indicated Reductions (EUIRP) and the construction time (EURCD) and reduced by the physical lifetime (EURCPL). Indicated reductions are calculated from costs and curve parameters:

a. EUIRP=1/(1+((xmax((PCost*ECoverage+PCostExo)* PCostM,0.01)*EURCstM)/EUPCostN)**EUPVF) [2004 Curve Parameters]
b. EUIRP=ln(EURCC/Infla/(EUPCostN/PCostM/EURCstM))/ EUPVF*ECoverage [2009 Curve Parameters]

Reduction capital cost and pollutant reduction factor for policies where reductions are specified first:

EURP=RPolicy*ECoverage

EURCC=(1/RPFull-1)**(1/EUPVF)*EUPCostN/EURCstM/ (EUCCR+EUROCF)*Infla [2004 Curve Parameters]

EURCC=(EUPCostN/EURCstM)*Exp(EUPVF*RPFull)*Infla [2009 Curve Parameters]

Reduction capital cost and pollutant reduction factor for other policies:
EURP=0
EURCC=0

Reduction multiplier by area:
EURM=(1-EURP)*(1-EUVR)*XEURM

Procedure UnPReductions

With the sector level reduction requirement established, *UnPReductions* determines the reduction amount and emission costs for individual units using methods determined by the value of UnPRSw. The first option (in subprocedure *UnCurve*) is for individual units to receive the same reductions levels (UnRP) and costs (UnRCC) as the plant-type based results from the previous procedure (EURP, EURCC). Second, the subprocedure *UnReduce* compares plant-type reductions to an exogenous value. Then, costs are based on the higher of the two reduction levels and the abatement curve parameters (EUPCostN, EUPVF).

UnPReductions Inputs and Outputs
Key Inputs
EUCCR (Area,Year) = Pollution Reduction Capital Charge Rate ($/$)
EURCC (FuelEP,Plant,Poll,Area,Year) = Reduction Capital Cost ($/Tonnes)
EURP (FuelEP,Plant,Poll,Area,Year) = Pollutant Reduction (Tonnes/Tonnes)
RPOCX (PRTech,FuelEP,Poll,Plant,Year) = Pollution Reduction Multiplier (Tonnes/TBtu/Tonnes/TBtu)
XUnRP (Unit,FuelEP,Poll,Year) = Pollution Reduction (Tonnes/Tonnes)
XUnRCC (Unit,FuelEP,Poll,Year) = Pollution Reduction Capital Cost ($/Tonnes)
Key outputs
UnRCC (Unit,FuelEP,Poll,Year) = Pollution Reduction Capital Cost ($/Tonnes)
UnRM (Unit,FuelEP,Poll,Year) = Pollution Reduction Multiplier (Tonnes/Tonnes)
UnRP (Unit,FuelEP,Poll,Year) = Pollution Reduction (Tonnes/Tonnes)

Key equations for unit-level costs and reductions in *UnPReductions* include:

Key Equations:
UnPReductions

Pollution reduction factor and capital cost for plant-type based cost:

a. UnRP=EURP
b. UnRCC=EURCC

Pollution reduction factor and capital cost for semi-exogenous reductions:

a. UnRP=Maximum(EURP, XUnRP)

b. UnRCC=(1/UnRP-1)**(1/EUPVF)*EUPCostN/EURCstM/(EUCCR+UnROCF) *Infla [2004 Curve Parameters]
c. UnRCC=(EUPCostN/EURCstM)*Exp(EUPVF*UnRP)*Infla [2009 Curve Parameters]

Pollution reduction multiplier:

UnRM=(1-UnRP)*(1-UnRP2)*(1-EUVR)

Where: UnRP2 is a variable slot for a second source of reductions, but is currently unused.

Procedure PolCoefficients

The *PolCoefficients* procedure calculates both the sector-wide and unit-level average emissions coefficients based on the input default marginal emissions coefficient adjusted by the required reduction amount. This allows for the emissions inventory to match the new reduced value. The average coefficient (POCA, UnPOCA) are calculated from the product of the exogenous coefficients (POCX, UnPOCX) and the Emissions Reduction Multipliers (EURM, UnRM). Coefficients for black carbon are calculated from the coefficients for particulate matter smaller than 2.5 micrometers. Additionally, a coefficient for approximate emissions per GWh (UnPOCGWh) is calculated for use in generation dispatch for pollution-related policies.

PolCoefficients Inputs and Outputs

Key Inputs

EURM (FuelEP,Plant,Poll,Area,Year) = Reduction Multiplier by Area (Tonnes/Tonnes)
POCX (FuelEP,Poll,Plant,Area,Year) = Marginal Pollution Coefficient (Tonnes/TBtu)
UnDmd (Unit,FuelEP,Year) = Energy Demand (TBtu)
UnEGA (Unit,Year) = Generation (GWH)
UnPOCX (Unit,FuelEP,Poll,,Year) = Pollution Coefficient (Tonnes/TBtu)
UnRM (Unit,FuelEP,Poll,Year) = Pollution Reduction Multiplier (Tonnes/Tonnes)

Key outputs

POCA (FuelEP,Plant,Poll,Area,Year) = Average Pollution Coefficients (Tonnes/TBTU)
UnPOCA (Unit,FuelEP,Poll,Year) = Average Pollution Coefficient (Tonnes/TBtu)
UnPOCGWh (Unit,Poll,Year) = Pollution Coefficient (Tonnes/GWh)

Key Equations in *PolCoefficents* include:

Key Equations:
PolCoefficients

Average pollution coefficient by plant type, fuel type, and area:
POCA=POCX*EURM

Average pollution coefficient by unit and fuel:
UnPOCA=UnPOCX*UnRM

Pollution coefficient in tonnes/GWh by unit:
UnPOCGWh = [∑(UnDmd*UnPOCA)]/UnEGA

Procedure PollutionCost

PollutionCost uses emission coefficients and trading allowances to compute the marginal and average pollution costs (tax rates, fees, or other per MWh costs directly arising out of emissions policies) and transmission pollution costs. The essential construction of the pollution tax rates is the product of the price of emissions trading allowances (ETAPr), the fuel-based pollution coefficient (UnPOCA, POCXNew), the heat rate (UnHRt, HRTM), and fractions of fuel used for each plant type (UnFlFr, FlFrNew), with various adjustments for unit conversion.

Unit Gratis Permits are also calculated for use in later pollution-related procedures. Because many GHG policy schemes link gratis permits to emissions targets, both terms are sometimes used.

PollutionCost Inputs and Outputs
Key Inputs
ETAPr (Market,Year) =Cost of Emission Trading Allowances ($/Tonnes)
UnPOCA (Unit,FuelEP,Poll,Year) = Average Pollution Coefficient (Tonnes/TBtu)
UnEGA (Unit,Year) = Generation (GWH)
Key outputs
LLPoTxR (Node,NodeX,Market,Year) = Pollution Costs for Transmission ($/MWH)
PoTxR (Plant,GenCo,Year) = Pollution Tax Rate ($/MWH)
PoTRNew (Plant,Area,Year) = Emission Cost for New Plants ($/MWH)
UnGP (Unit,FuelEP,Poll,Year) = Unit Intensity Target or Gratis Permits (kg/MWh)
UnPoTR (Unit,Year) = Marginal Pollution Tax Rate ($/MWh)

Key equations in *PollutionCost* include:

Key Equations:
PollutionCost

Pollution costs for transmission:

LLPoTxR=LLPOCX*ETAPr/1000

Marginal pollution tax rate:

UnPoTR= ∑(ETAPr/PolConv*UnPOCA*UnHRt/1e9*UnCoverage*UnFlFr)

Emission cost for new plants:

PoTRNew= ∑(ETAPr/PolConv*(POCXNew*HRTM/1e6-GPNew)/1000*FlFrNew)

Pollution tax rate:

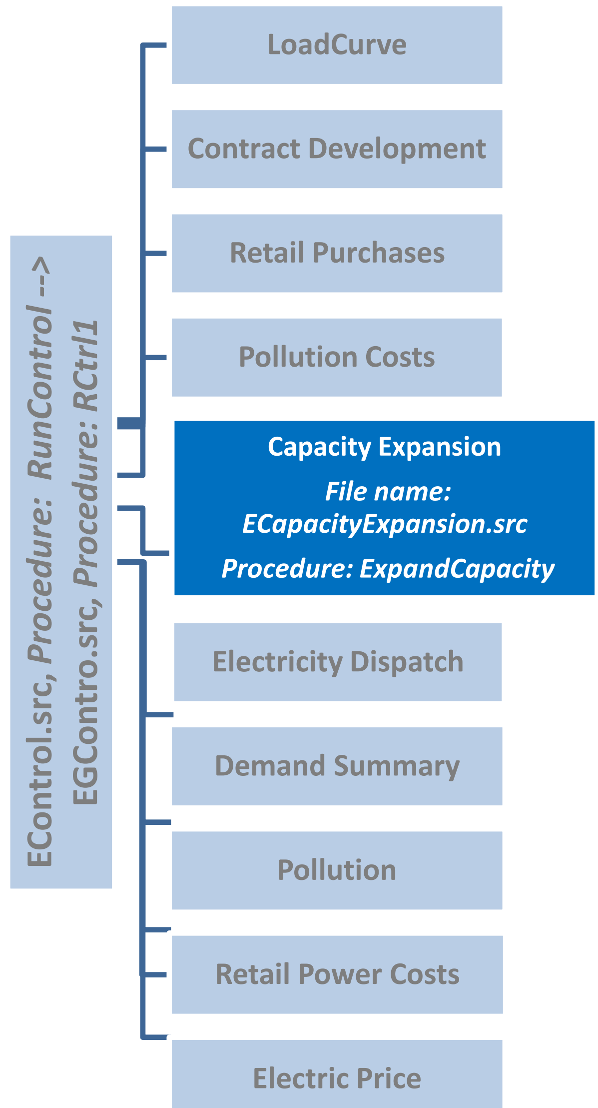
PoTxR=PoCstG/GenG, *where*

a. PoCstG=PoCstG+UnPoTR*UnEGA, *accumulated across units*
b. GenG=GenG+UnEGA, *accumulated across units*

6. Capacity Expansion Submodule

ECapacityExpansion.src contains the source code and procedures that make up the capacity expansion submodule. The capacity expansion submodule's main procedure is named *ExpandCapacity,* and its call is initiated in the *RunControl* procedure inside *EControl.src*. From the *RunControl* procedure in *EControl.src*, procedure *RCtrl1* is called which is housed in *ECapacityExpansion.src* which in turn calls *ExpandCapacity*. Capacity expansion is called after load curve, contract development and dispatch, and pollution submodules have been executed.

Figure 19: Capacity Expansion in Electric Supply



Submodule Objective

The capacity expansion submodule builds new generating units to meet the increasing yearly capacity demands.

Submodule Methodology

The decision to build new generation capacity involves many factors. ENERGY 2020 includes a variety of algorithms to simulate the decision to build new capacity. These algorithms include information on wholesale prices, desired reserve margins, the cost of new capacity (construction, operating, and environmental costs), political and social preferences, regulations, standards, and subsidies. The model is adjusted and customized to simulate the decision making process at a particular time and location.

One method is to forecast capacity requirements using a desired reserve margin, then to construct the cheapest plant which is politically feasible. Given the current peak

Methods of building new capacity

demand the model forecasts the expected demand into the future. The number of years which are forecasted depends on the construction time of the units being built. The forecasted peak demand is compared to the existing capacity (for intermittent sources such as wind, capacity is derated), capacity to be retired, and capacity under construction to decide the amount of new capacity.

Another method is to build new capacity based on prices. The construction of new capacity depends on the wholesale price of power. As the wholesale price rises, new capacity will be constructed even if the reserve margin is higher than “desired”. Conversely, if the wholesale price is low, then new capacity will not be constructed even if it is “needed”.

There is also a method which combines wholesale prices and a desired reserve margin. In this case capacity is constructed if the wholesale price is high and capacity is needed. The amount constructed depends on the desired reserve margin.

The actual method used depends on the situation (amount of regulation) in the particular area and is a user-specified input to the model. Within a single model some generating companies (GenCo) can use one strategy while another generating company uses a different one.

Any of the methods can generate over building or under building although they will correct themselves over time. The model’s construction of new capacity depends on simulated forecasts, and do not necessarily match future demand requirements. If too many new units are constructed by generating companies attempting to take advantage of higher prices, this will lead to excess capacity. Likewise, if the costs or barriers to construction are too high, there may be insufficient new units to meet demand requirements. This is the desired result since historically we often see regions in an over-capacity or under-capacity situation.

Once the amount of new capacity is determined, the model then decides the type of capacity. The two primary factors are which types of capacity are politically feasible and the costs of the capacity. The relative political feasibility of constructing various plant types is an input to the model.

The new capacity costs include capital costs (including financing), O&M costs, fuel costs, environmental costs, and subsidies. A levelized cost is computed for each type of power (peaking, intermediate, and baseload) the least cost power is selected.

Building renewable power

Renewable power may be selected as part of the normal plant type selection process, but it can also be built to meet a renewable portfolio standard (RPS). An RPS is expressed as a fraction of sales which must be met with renewable power. The model selects the plant types which qualifies for the RPS and calculates the levelized cost for each plant type. The amount of new capacity is a function of the RPS requirement and the current renewable generation. The type of renewable power developed is determined using a qualitative choice function using the cost of each type of renewable power. These costs are all adjusted for the expected capacity factor of each renewable resource. The capital cost of the renewable resource will increase as the availability of the renewable resource is depleted.

The key inputs to the capacity expansion submodule are listed below with variable names indicated in parenthesis.

Figure 20: Procedure ExpandCapacity in ECapacityExpansion.src

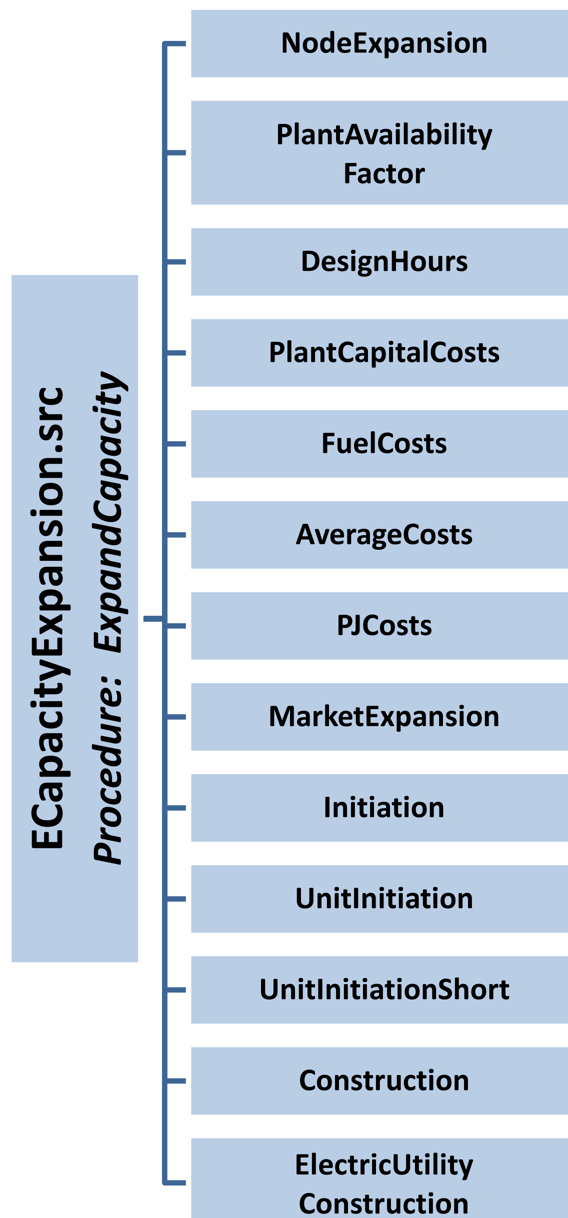
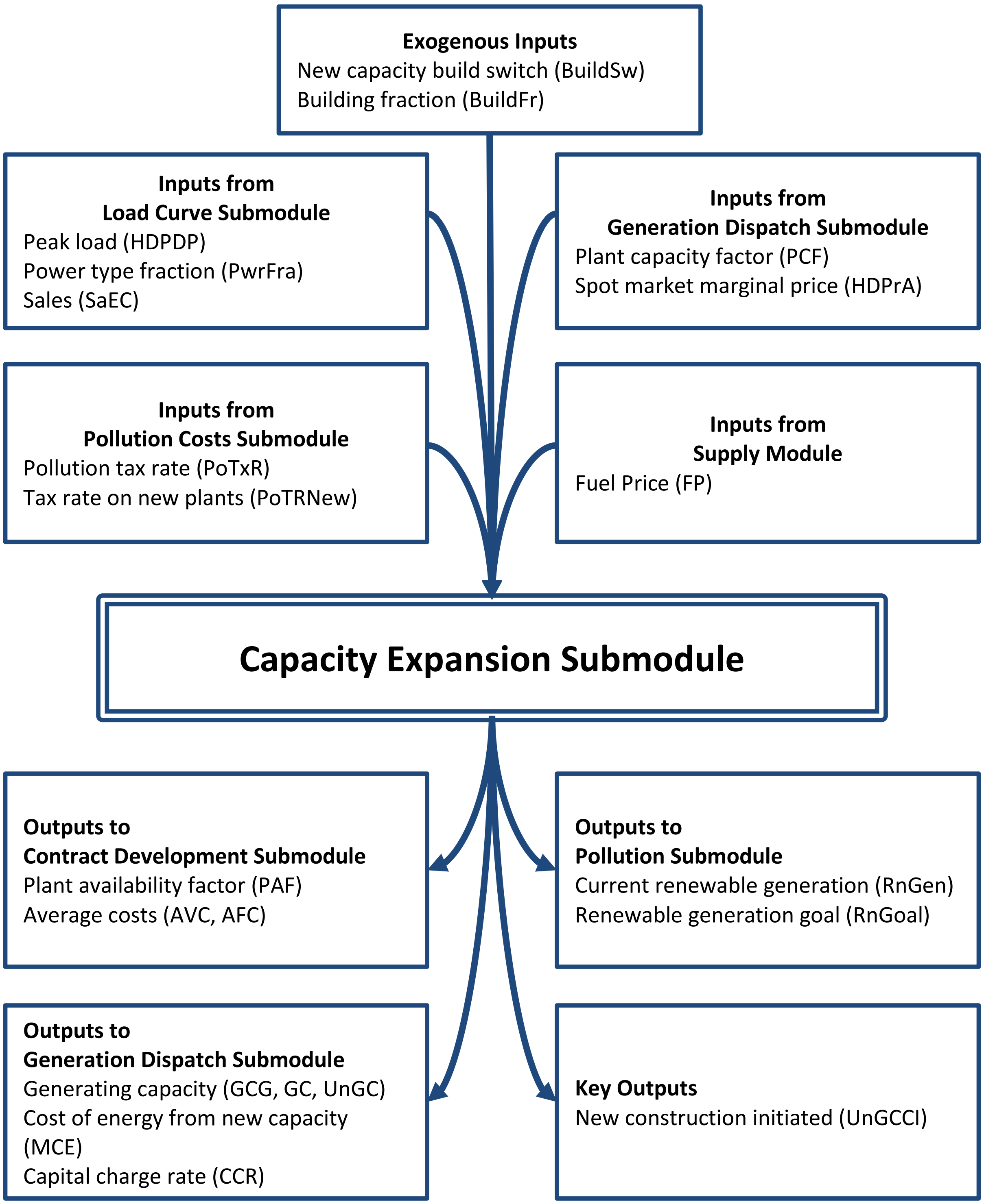


Figure 21. Capacity Expansion Submodule Diagram of Inputs and Outputs



Submodule Procedures

The main procedures called from the *ExpandCapacity* procedure in ECapacityExpansion.src are shown in Figure 20 above. Table 24 summarizes the objective of each of the procedures within capacity expansion and identifies the key outputs of each.

Table 24. Description of Capacity Expansion Procedures

Procedure Description	Key Outputs
1. NodeExpansion Uses prior year's capacity (GC), new capacity initiated (HDGCCI), peak load (HDPDP), and capacity under construction (PCUC) to estimate the current year's generation needs by node. The outputs from this procedure, forecasted generation (HDFGC) and generation requirements (HDRq) are sent directly as input to the *MarketExpansion* procedure.	Forecasted generation (HDFGC), Forecasted generation requirements (HDRq)
2. PlantAvailabilityFactor Computes plant availability factor for each plant type.	Plant availability factor (PAF)
3. DesignHours Calculates the total hours that each plant type is designed to run during the course of a year by generating company and type of power (peak, intermediate, and base).	Design hours (DesHr)
4. PlantCapitalCosts Takes into account the total capacity already developed (GC) within an area for each plant type and capacity under construction (PCUC). Capital cost multiplier is calculated using maximum potential capacity for an area compared to already developed capacity. Overnight construction cost is calculated to give the price for developing each plant type in a given area.	Potential generation capacity (GCPot), Capital cost multiplier (GCCCM), Overnight construction costs (GCCC)

Procedure Description	Key Outputs
5. FuelCosts This procedure calculates the fuel price (EUFP) for given plant types based on the type of fuel that they use. Then, it calculates the unit fuel costs (UFC) based on the fuel prices (FP) and heat rates (HRTM).	Unit fuel cost (UFC)
6. AverageCosts Calculates the average variable costs for each plant based on the fixed costs and operation and maintenance costs of those plants.	Average variable costs (AVC)
7. Project Costs This procedure determines the lifecycle costs of each type of capacity. For each plant type, it calculates what the capital charge rate, fixed costs, variables costs, and costs of energy for a new plant.	Capital charge rate (CCR), Cost of energy from new capacity (MCE), Marginal fixed costs (MFC), Marginal variable costs (MVC)
8. MarketExpansion Computes the amount of capacity constructed and the price of that new construction, which depends on the capacity expansion strategy of each generating company.	Decision price for new construction (HDPrDP), Indicated planned generation capacity (HDIPGC), Difference between spot market price and price of new capacity (PriceDiff)
9. Initiation Calculates new capacity initiated in renewable expansion programs such as RPS in which expansion rates are set to meet specific goals, and renewable construction due to FIT (Feed-In Tariff) Contracts.	New capacity initiated (HDGCCI), Capacity of projects initiated (PJCIHD), Renewable capacity initiated (RnGCCI),Renewable market share (RnMSF)

Procedure Description	Key Outputs
10. UnitInitiation The *UnitInitiation* procedure uses the new capacity initiated (HDGCCI) and renewable capacity initiated (RnGCCI) calculations to build new electric generating units in the prescribed areas.	Generating capacity initiated (UnGCCI)
11. UnitInitiationShort Ensures that the unit counters are adjusted to account for the new exogenous units.	Number of units (UnCounter)
12. ElectricUtilityConstruction This procedure updates the construction work in progress, the capacity under construction, the capacity completion rate, and the new generating capacity total based on the new generating units that have been constructed (UnCUC).	Construction work in progress (CW), Generation capacity (GC), Generation capacity (GCAr), Capacity completion rate (GCCR), Capacity under construction (PCUC)
13. CGInitiation This procedure calculates the cogeneration capacity initiated based on the additional exogenous cogeneration capacity (CgUnGCCI).	Generating capacity initiated (UnGCCI)
14. CGConstruction This procedure calculates the amount invested into building exogenous cogeneration units.	Cogeneration investments (CgInvUnit)

The following sections describe each of the procedures summarized above in more detail.

Procedure NodeExpansion

The *NodeExpansion* procedure uses the prior year's values of capacity (GC), new capacity initiated (HDGCCI), peak load (HPDP), and capacity under construction (PCUC) to estimate the current year's generation needs by node. This procedure's key outputs include forecasted values for generating capacity (HDFGC) and generation requirements by node (HDRq). Both of these outputs are sent as inputs to the *MarketExpansion* procedure. Table 25 summarizes the variable names and definitions of the key inputs and outputs of this procedure.

Table 25: Input and Output Variables - NodeExpansion

***NodeExpansion* Inputs and Outputs**
Key inputs
DRM (Node,Year) = Desired Reserve Margin (MW/MW)
PCUC (Plant,Node,GenCo,Area,Year) = Capacity under Construction (MW)
GC (Plant,Node,GenCo,Prior) = Generation Capacity (MW)
HDGCCI (Plant,Node,GenCo,Area,Prior) = New Capacity Initiated (MW)
HDPDP (Node,TimeP,Month,Year) = Peak Load in Interval (MW)
Key outputs
HDFGC (Node,Year) = Forecasted Generation Capacity (MW)
HDRq (Node,Year) = Hourly Dispatch Forecasted Generation Requirements (MW)

Procedure PlantAvailabilityFactor

The objective of the *PlantAvailabilityFactor* procedure is to calculate a proportion of hours of generation per year that each generating company's plants will generate. Inputs to this procedure include scheduled outage rates (HDSOR), unscheduled outage rate fractions (UOR), the number of hours in each time interval (HDHours). The plant availability factor (PAF) is calculated and ultimately used as input to the electric generation dispatch submodule to calculate costs for individual units in the electric generation dispatch submodule.

The equation used to calculate the plant availability factor is listed below.

Key Equation:
PlantAvailability Factor

Plant availability factor:

PAF = (1-∑(HDSOR * HDHours)/∑(HDHours*(1-UOR)

Table 26 summarizes the variable names and definitions of the key inputs to and outputs from the *PlantAvailabilityFactor* procedure.

Table 26: Input and Output Variables - PlantAvailabilityFactor

***PlantAvailabilityFactor* Inputs and Outputs**
Key inputs HDHours (TimeP,Month) = Number of Hours in the Interval (Hours) HDSOR (Plant,GenCo,TimeP,Month,Year) = Scheduled Outage Rate (MW/MW) UOR (Plant,GenCo,Year) = Unscheduled Outage Rate (Fraction) **Key outputs** PAF (Plant,GenCo,Year) = Plant Availability Factor (MW/MW) HDHours (TimeP,Month) = Number of Hours in the Interval (Hours) HDSOR (Plant,GenCo,TimeP,Month,Year) = Scheduled Outage Rate (MW/MW) UOR (Plant,GenCo,Year) = Unscheduled Outage Rate (Fraction)

Procedure DesignHours

The *DesignHours* procedure takes the number of hours in each time interval, and calculates the total hours that each plant type is designed to run during the course of a year by generating company and type of power (peak, intermediate, and base).

The hours for peak or intermediate power is simply the number of hours in the time interval (HDHours) with the time periods mapped into power blocks of peak and intermediate (TPrMap). For baseload power blocks, the number of hours the plants are designed to be available is not larger than the plant availability (one minus outage rate for new plants). The equations used for the design hours' calculation are shown below.

Key Equations:
DesignHours

Design hours for plants in peak and intermediate power blocks:

DesHr = ∑ (HDHours*TPRMap)

Design hours for plants in baseload power blocks:

DesHr = 8760*(1-ORNew)

Table 27 summarizes the key inputs to and outputs from the *DesignHours* procedure.

Table 27: Input and Output Variables - DesignHours

***DesignHours* Inputs and Outputs**
Key inputs HDHours (TimeP,Month) = Number of Hours in the Interval (Hours) ORNew (Plant,Area,Year) = Outage Rate for New Plants (MW/MW) TPrMap (TimeP,Power) = TimeP to Power Map **Key outputs** DesHr (Plant,Power,GenCo,Year) = Design Hours (Hours)

Procedure PlantCapitalCosts

The *PlantCapitalCosts* procedure determines the capital costs of new plants. For some plant types, capacity within an area may be constrained; for example with hydroelectric power, costs increase and potential capacity decrease as the amount of existing capacity increases. New generating capacity potential (GCPot) is assigned and a multiplier on costs from potential depletion (GCCCM) is determined based on an exogenously-set flag for each plant type (GCCCFlag). This flag (GCCCFlag) indicates the relationship between new potential for generating capacity and the capital costs of new plants.

1. *New potential is exogenous and capital costs increase as potential is depleted*

   If GCCCFlag equals one (small hydro and pumped hydro), then new potential is exogenously defined (XGCPot) and the capital cost depletion multiplier (GCCCM) gets smaller as potential is depleted.

2. *Plants whose potential is limited (and exogenous), but capital costs are fixed until all potential is developed*

   If GCCCFlag equals two (Biomass, Wind, Solar, FuelCell, Wave, Geothermal), then potential is exogenously defined (XGCPot), and the capital cost depletion multiplier (GCCCM) does not change (equals one).

3. *Plants whose potential is limited by GRP*

   If GCCCFlag equals three (Landfill Gas), then the new capacity potential is a function of GRP, and capital costs increase as potential is depleted.

4. *Plants whose potential is unlimited*

   If GCCCFlag equals zero (most conventional technologies), then the new capacity potential is exogenous and there is no impact from the capital cost depletion multiplier.

The generation capital cost (GCCC) is then calculated as the normal capital cost (GCCCN) times the capital cost depletion multiplier (GCCCM) as shown below.

Key Equation:
PlantCapitalCosts

<u>*Generation capital cost of new plants:*</u>
GCCC=GCCCN*GCCCM*Infla

The capital cost of new plants (GCCC) is used to calculate marginal fixed costs (MFC) in the *ProjectCosts* procedure and to determine unit capital costs (UnGCCC) in

UnitInitiation. Table 28 summarizes the variable names and definitions of the key inputs and outputs for this procedure.

Table 28: Input and Output Variables - PlantCapitalCosts

***PlantCapitalCosts* Inputs and Outputs**
Key inputs
GCCCFlag (Plant,Area,Year) = Plant Capital Cost Flag
GCCCN(Plant,Node,Area) = Overnight Construction Costs ($/KW)
XGCPot (Plant,Node,Area,Year) =Exogenous Maximum Potential Generation Capacity (MW)
Key outputs
GCCC (Plant,Node,Area,Year) = Overnight Construction Costs ($/KW)
GCCCM (Plant,Node,Area,Year) = Capital Cost Depletion Multiplier ($/$)
GCPot (Plant,Node,Area,Year) = Maximum Potential Generation Capacity (MW)

Procedure FuelCosts

The purpose of the *FuelCosts* procedure is to calculate a fuel cost (UFC) for each plant type. It uses fuel prices (FP) as input mapped to plant type and generating companies as the variable (EUFP). The unit fuel cost is then calculated as the fuel price (EUFP) times the heat rate of the given plant type. Nuclear unit fuel costs are an exception and are exogenously input ($XUFC_{Nuclear}$). The key equation for the *FuelCosts* procedure is shown below.

Key Equations:
FuelCosts

Unit fuel cost of plants:

UFC=EUFP*HRTM/1000

Unit fuel costs of nuclear plants:

$UFC_{Nuclear}=XUFC_{Nuclear}*Infla$

The unit fuel costs (UFC) are used as input to *AverageCosts* to calculate average variable costs. Table 29 summarizes the variable names and definitions of the key inputs and outputs for *FuelCosts*.

Table 29: Input and Output Variables - FuelCosts

***FuelCosts* Inputs and Outputs**
Key inputs
FP (Prices,Area,Year) = Delivered Fuel Price ($/mmBtu)
HRTM (Plant,Node,GenCo) = Marginal Heat Rate (BTU/KWH)
XUFC (Plant,GenCo,Year) = Unit Fuel Cost ($/MWh)
Key outputs

***FuelCosts* Inputs and Outputs**
EUFP (Plant,GenCo,Year) = Fuel Price for Electric Utility ($/MBTU) UFC (Plant,GenCo,Year)= Unit Fuel Cost ($/MWh)

Procedure AverageCosts

The *AverageCosts* procedure calculates the average variable costs for each plant based on the fixed costs and operation and maintenance costs of those plants.

The average cost (AVC) is calculated as plant fuel cost (UFC) times a spot market price ratio (SPRatio, which is by default equal to 1.0 and is used as a policy variable) plus plant operation and maintenance cost (UOMC) plus a pollution tax rate (PoTxR) if applicable.

Key Equation:
AverageCosts

Average variable costs by plant type:
AVC=UFC*SPRatio+UOMC*Infla+PoTxR

The average variable costs are then used as input to the electric generation dispatch submodule to determine the unit bids and sent as input to the contract development and retail purchases submodules to determine the cost of contracts. Table 30 summarizes the variable names and definitions of the key inputs and outputs of the *AverageCosts* procedure.

Table 30: Input and Output Variables - AverageCosts

***AverageCosts* Inputs and Outputs**
Key inputs PoTxR (Plant,GenCo,Year) = Pollution Tax Rate ($/MWh) SPRatio (Plant,GenCo,Year) = Spot Fuel Price Ratio (Fraction) UFC (Plant,GenCo,Year) = Unit Fuel Cost ($/MWh) UOMC (Plant,GenCo,Year) = Unit O&M Costs ($/MWh) **Key outputs** AVC (Plant,GenCo,Year) = Average Variable Costs ($/MWh)

Procedure ProjectCosts

The *ProjectCosts* procedure determines the lifecycle costs of each type of capacity. For each plant type, it calculates the capital charge rate (CCR), fixed costs (MFC), variables costs (MVC), and marginal cost of a new plant (MCE).

The cost of energy from new capacity (MCE) is computed by combining the variable costs (MVC) and the fixed costs (MFC) using the design hours of operation (DesHr) for each type of Power (Baseload, Intermediate, and Peaking).

The key equations used in the *ProjectCosts* procedure are listed below.

Key Equations:
ProjectCosts

Capital charge rate:
CCR = (1-DIVTC/(1+WCC+DRisk+InSm)-TaxR*(2/GCTL)/(WCC+DRisk+InSm+2/GCTL))*(WCC+DRISK)/(1-(1/(1+WCC+DRisk))**GCBL) / (1-TaxR)

Fixed costs of new plants ($/KW):
MFC=CCR*GCCC+UFOMC*Infla

Variable costs of new plants ($/MWh):
MVC=UOMC*Infla+FPEU*HRTM/1000+PoTRNew+PoTRNewExo*Infla

Marginal cost of electricity:
MCE=MVC+MFC/DesHr*1000-Subsidy

The capital charge rate (CCR) is used as input for calculating unit fixed costs in *FixedCosts* and for calculating stranded investment costs in *StrandedInvestmentsForRetiredUnits* in the electric generation dispatch submodule. It is also used to calculate the marginal fixed costs for new plants (MFC) in the capacity expansion submodule. The marginal fixed costs (MFC) and the marginal variable costs (MVC) are both inputs to calculating the cost of energy for new capacity (MCE). The cost of energy for new capacity is used as an input to calculate the fraction of new capacity to be constructed. Table 31 summarizes the variable names and definitions of the key inputs to and outputs from the *ProjectCosts* procedure.

Table 31: Input and Output Variables - ProjectCosts

***ProjectCosts* Inputs and Outputs**
Key inputs DIVTC (Plant,GenCo,Year) = Device Investment Tax Credit ($/$) DRisk (Plant,GenCo,Year) = Device Risk Premium ($/$) GCBL (Plant,GenCo,Year) = Generation Capacity Book Life (YRS) GCCC (Plant,Node,Area,Year) = Overnight Construction Costs ($/KW) InSm (Year) = Smoothed Inflation Rate (1/Yr) TaxR (GenCo,Year) = Income Tax Rate ($/$) UFOMC (Plant,GenCo,Year) = Unit Fixed O&M Costs ($/KW) UOMC (Plant,GenCo,Year) = Unit O&M Costs ($/MWh) WCC (GenCo,Year) = Weighted Cost of Capital (1/Yr) **Key outputs** CCR (Plant,GenCo,Year) = Capital Charge Rate (1/Yr) MCE (Plant,Power,Node,GenCo,Area,Year) = Cost of Energy from New Capacity ($/MWh)

***ProjectCosts* Inputs and Outputs**
MFC (Plant,Node,GenCo,Area,Year) = Marginal Fixed Costs ($/KW) MVC (Plant,Node,GenCo,Area,Year) = Marginal Variable Costs ($/MWh)

Procedure MarketExpansion

This procedure computes the amount of capacity to be constructed and the price of that new construction, which depends on the capacity expansion strategy of each generating company.

The capacity under construction for a given node is constrained by current capacity; when a large enough portion of the total system is under construction, new construction is temporarily curtailed.

There are several methods that the model can use to determine which protocol it should follow when deciding whether or not to build new capacity. This build switch (BuildSw) is assigned in the data file, *EGData.src*. The optional values for the build switch include the following:

- BuildSw=4: Building is exogenous
- BuildSw=5: Utilities build to meet reserve margin or if prices are high
- BuildSw=6: Utilities build only to meet peak
- BuildSw=7: Utilities build new capacity if clearing prices are greater than the cost of new capacity
- BuildSw=9: Utilities build new capacity based on prices relative to the amount of capacity constructed

If the user would like to use a different method for building new capacity, then it must be set in *EGData.src* before running the model. The specified build switch procedure calculates how much planned generation capacity (HDIPGC) is to be built, but no generating units are actually constructed yet.

The amount of new capacity is further determined by a build fraction (BuildFr). This build fraction is exogenously-specified and represents the fraction of "needed" capacity that will be built in the given year. In many instances, we want to build only a portion of the "needed" capacity in a given year to ensure that overbuilding does not occur due to events such as exogenous capacity coming online.

Table 32 summarizes the variable names and definitions of the key inputs to and outputs from *MarketExpansion*.

Table 32: Input and Output Variables - MarketExpansion

MarketExpansion Inputs and Outputs
Key inputs HDPrA (Node,TimeP,Month,Year) = Spot Market Marginal Price ($/MWh) PCUC (Plant,Node,GenCo,Area,Year) = Capacity under Construction (MW) **Key outputs** HDPrDP (Power,Node,GenCo,Year) = Decision Price for New Construction ($/MWh) HDIPGC (Power,Node,GenCo,Area,Year) = Indicated Planned Generation Capacity (MW) PriceDiff (Power,Node,GenCo,Area,Year) = Difference between Spot Market Price and Price of New Capacity

Procedure Initiation

This procedure determines the type of new capacity initiated and initiates capacity from other parts of the model. Included are renewable expansion programs such as RPS in which expansion rates are set to meet specific goals, and renewable construction due to FIT (Feed-In Tariff) Contracts.

The amount of capacity awarded to each project is based on the amount of power needed (HDIPGC) and the maximum (PJMax) and minimum (PJMNPS) project sizes.

For the RPS project, renewable expansion is set to meet a goal (RnGoal). The renewable capacity initiated (RnGCCI) cannot exceed the maximum potential capacity (GCPot) for a given plant type and area. The renewable market share fraction (RnMSF) is based on the marginal cost for each renewable plant type and its FIT contract price. Table 33 summarizes the key input and output variables of procedure *Initiation*.

Table 33: Input and Output Variables - Initiation

Initiation Inputs and Outputs
Key inputs GCDev (Plant,Node,Area,Year) = Generation Capacity Developed (MW) GCPot (Plant,Node,Area,Year) = Maximum Potential Capacity (MW) HDIPGC (Power,Node,GenCo,Area,Year) = Indicated Planned Generation Capacity (MW) **Key outputs** GrMSF (Plant,Node,GenCo,Area,Year) = Green Power Market Share (MW/MW) HDGCCI (Plantr,Node,GenCo,Area,Year)= New Capacity Initiated (MW) PJCIHD (Plant,Node,GenCo,Area,Year)= Capacity of Projects Initiated (MW/YR) RnGCCI (Plant,Node,GenCo,Area,Year) = Renewable Capacity Initiated (MW) RnMSF (Plant,Node,GenCo,Area,Year) = Renewable Market Share (GWh/GWh)

Procedure UnitInitiation

The *UnitInitiation* procedure uses the new capacity initiated and renewable capacity initiated calculations to build new electric generating units in the prescribed areas.

The unit indicated capacity initiated (UnIGCCI) is a temporary variable equal to the capacity initiated (HDGCCI) for economic or capacity reasons, but at minimum it must be enough to cover the renewable standards (RnGCCI). If the (UnIGCCI) is greater than zero, then a new unit will be initiated.

When a new unit is created, it is given its own designated slot among the list of units, known as a unit counter (UnCounter) as well as its own unique name (UnCode). The units are assigned all of the necessary parameters such as how much generating capacity is initiated (UnGCCI), the node, the area, the plant type, the heat rate, the fuel type, the outage rate, the fixed cost, and the variable cost. Table 34 summarizes the key input and output variables from *UnitInitiation*.

Table 34: Input and Output Variables - UnitInitiation

***UnitInitiation* Inputs and Outputs**
Key inputs HDGCCI (Plant,Node,GenCo,Area,Year) = New Capacity Initiated (MW) RnGCCI (Plant,Node,GenCo,Area,Year) = Renewable Capacity Initiated (MW) **Key outputs** UnGCCI (Unit,Year) = Generating Capacity Initiated (MW)

Procedure UnitInitiationShort

The *UnitInitiationShort* procedure ensures that the unit counters are adjusted to account for the new exogenous units.

Before running this procedure, the unit counter (UnCounter) points to the last exogenous unit entered into the model. This procedure updates the UnCounter to adjust it by the number of endogenous units built. This is to ensure that previous unit entries to not get overwritten by newly created units. Table 35 lists the input and output variables of *UnitInitiationShort*.

Table 35: Input and Output Variables - UnitInitiationShort

UnitInitiationShort Inputs and Outputs
Key inputs UnCounter = Number of Units **Key outputs** UnCounter = Number of Units

Procedure ElectricUtilityConstruction

This procedure updates the construction work in progress, the capacity under construction, the capacity completion rate, and the new generating capacity total based on the new generating units that have been constructed.

When a unit is constructed, it generally does not produce its maximum capacity right away. Units take a specified number of years to be constructed based on the plant type, and typically, the maximum amount of capacity does not come online all in the same year. The capacity completion rate (GCCR) keeps track of how much capacity comes online for a new year per year. As new capacity comes online, the generation capacity of the unit (UnGC) gets updated by how much capacity was constructed for the given year (UnGCCR). Table 36 summarizes the variable names and definitions of the inputs and outputs of the *ElectricUtilityConstruction* procedure.

Table 36: Input and Output Variables - ElectricUtilityConstruction

ElectricUtilityConstruction Inputs and Outputs
Key inputs UnGCCI (Unit,Year) = Generating Capacity Initiated (MW) UnCUC (Unit,Year) = Capacity Under Construction (MW) **Key outputs** CW (Plant,GenCo,Year) = Construction Work in Progress (M$/YR) GC (Plant,Node,GenCo,Year) = Generation Capacity (MW) GCAr (Plant,Node,GenCo,Area,Year) = Generation Capacity (MW) GCCR (Plant,Node,GenCo,Year) = Capacity Completion Rate (MW/YR) PCUC (Plant,Node,GenCo,Area,Year) = Capacity under Construction (MW)

Procedure CGInitiation

This procedure calculates the cogeneration capacity initiated based on the additional exogenous cogeneration capacity.

As additional cogeneration unit capacity is initiated (CgUnGCCI), it is added to the previous capacity of the cogeneration units (XUnGCCI) to give the current generating capacity initiated (UnGCCI). Table 37 lists the key inputs and outputs of the *CGInitiation* procedure.

Table 37: Input and Output Variables - CGInitiation

***CGInitiation* Inputs and Outputs**
Key inputs CgUnGCCI (Fuel,ECC,Area,Year) = Cogeneration Unit Capacity Initiated (MW) XUnGCCI (Unit,Year) = Exogenous Generating Capacity Initiated (MW) Key outputs UnGCCI (Unit,Year) = Generating Capacity Initiated (MW)

Procedure CGConstruction

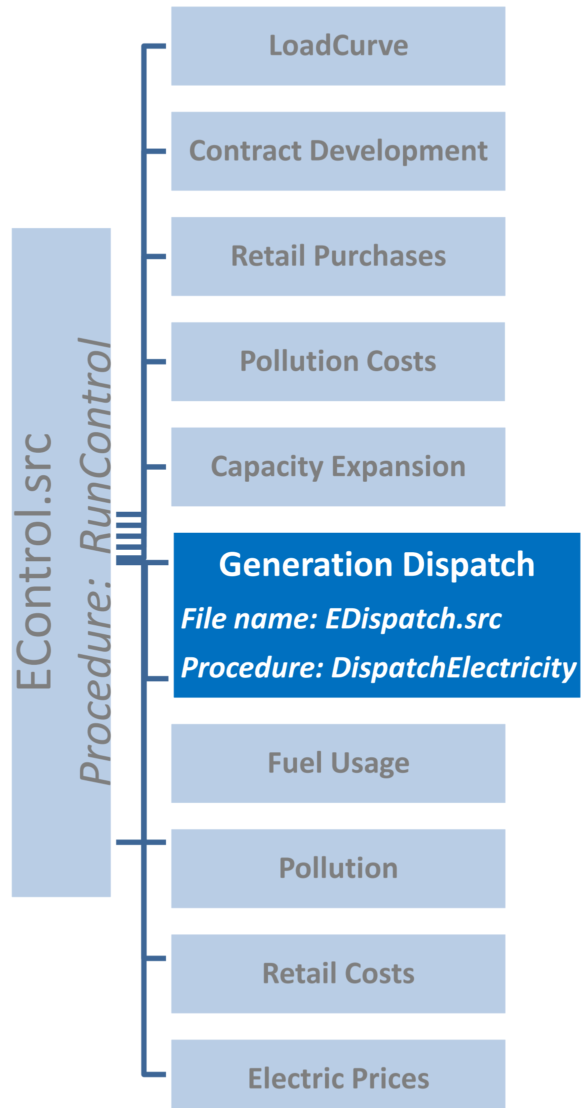
This procedure calculates the amount invested into building exogenous cogeneration units. The new cogeneration units are constructed much in the same way that the non-cogeneration units were constructed. The *CGConstruction* procedure points to the same *UnitConstruction* procedure that *UnitInitiation* calls. Table 38 lists the key inputs and outputs of the *CGConstruction* procedure.

Table 38: Input and Output Variables - CGConstruction

***CGConstruction* Inputs and Outputs**
Key inputs UnCW (Unit,Year) = Construction Costs ($M/YR) **Key outputs** CgInvUnit (ECC,Area,Year) = Cogeneration Investments (M$/YR)

7. Electric Generation Dispatch Submodule

Figure 22: Generation Dispatch in Electric Supply



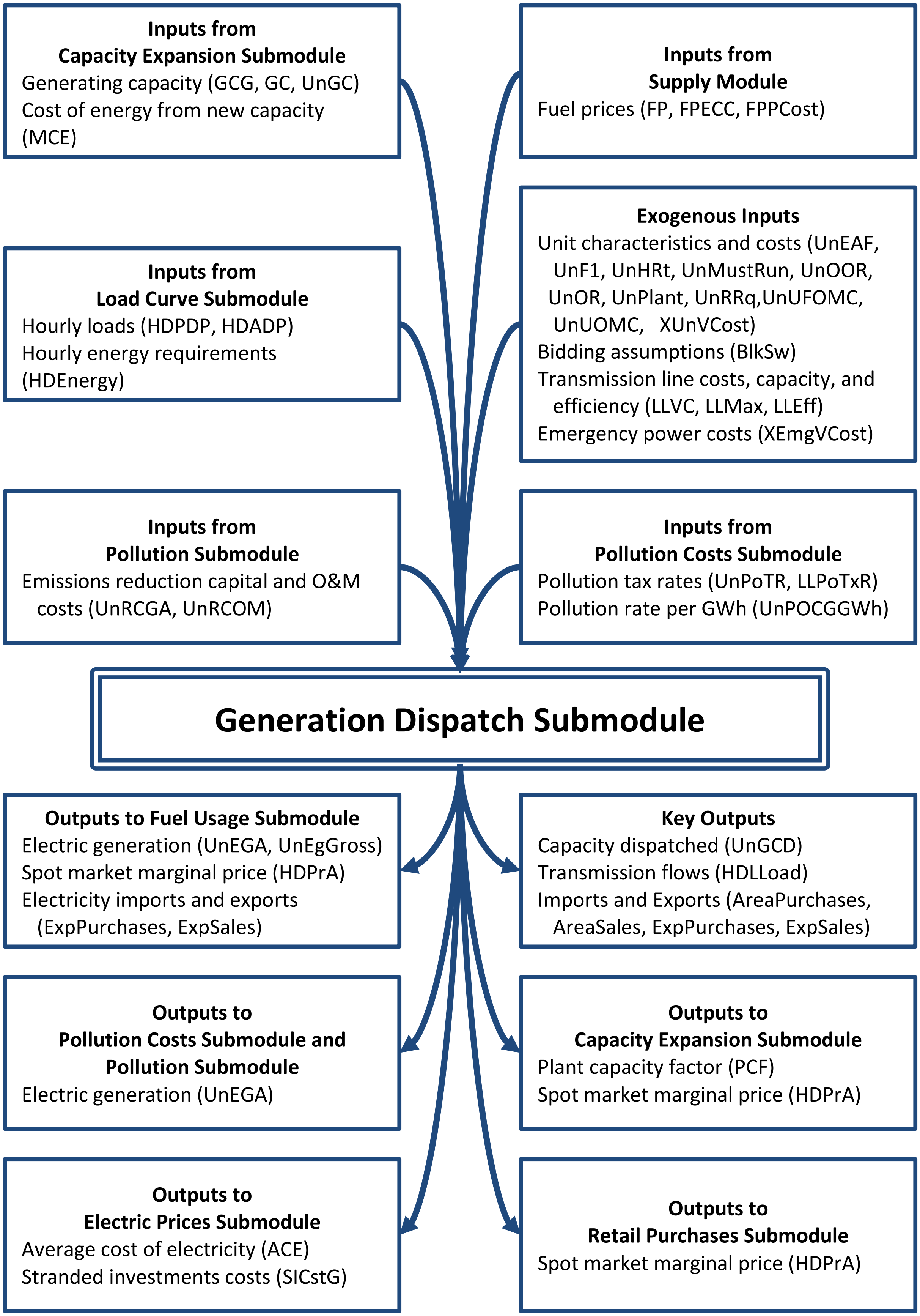
The *EDispatch.src* file contains the source code and procedures that make up the electric generation dispatch submodule. Its main procedure is named *DispatchElectricity* and is called from the *RunControl* procedure inside *EControl.src*. At the point when the electric generation dispatch submodule gets called, the load curves have been created, purchased power contracts have been developed and dispatched, initial pollution levels have been calculated, and based on demand requirements, new capacity has been built and is available for dispatch.

Submodule Objective

The objective of the electric generation dispatch submodule is to determine an optimal mix of capacity and generation to be dispatched by existing generating facilities within each month (season), time slice, and node that will meet the current year's electricity demand. Outputs from the submodule additionally include optimal transmission flows and resulting marginal prices.

Figure 23 illustrates the relationship of the electricity generation dispatch submodule to the rest of ENERGY 2020.

Figure 23. Generation Dispatch Submodule Diagram of Inputs and Outputs



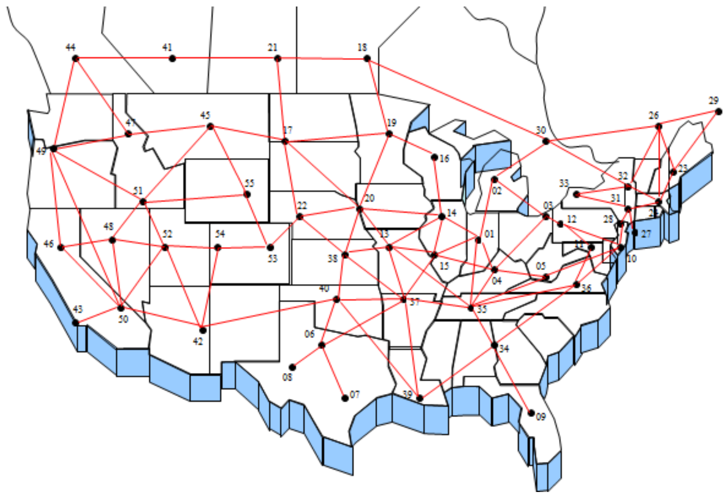
Submodule Methodology

The term used to describe the process of estimating electricity production levels and the cost of producing that electricity is "production costing". Within ENERGY 2020, production costing is simulated as a linear programming (LP) problem where the cost of the electric system is minimized subject to the constraints of meeting electric demands (generation balance constraint) while also meeting the overall system requirements. System requirements include the capability of only dispatching up to the generating capacity available (capacity availability constraint) and not exceeding the limits on the transmission lines (transmission constraint). An "emergency power" variable is used in the optimizing equation to ensure the LP is able to solve and is used as a check on the balance of the resulting transmission system. The LP solution provides the most cost effective mix of generating units needed to meet demand, and the outputs include unit capacity dispatched (UnGCD), transmission flows across the lines (HDLLoad), emergency generation (EmEGA), and the resulting marginal prices at each transmission node (HDPrA).

Electric System

The electric system in ENERGY 2020 is simulated as a set of nodes connected by transmission lines. The transmission lines are assigned line capacities to and from nodes (LLMax), transmission efficiencies (LLEff), and wheeling costs across the lines (LLVC). The actual transmission nodes and lines defined in ENERGY 2020 are able to be customized; however, the standard version of the model has 110 nodes represented across North America which are typically aggregated into a smaller number of nodes of interest. Figure 24 illustrates an example of a transmission network represented in ENERGY 2020.

Figure 24. Sample Transmission Network in ENERGY 2020



Each node consists of its own unique, specified demand, which is met by a pool of resources consisting of the generating units as well as emergency generation. The generating units are able to send electricity to neighboring nodes via the transmission lines. Each electric generating unit is exogenously-specified with defining characteristics. These characteristics include a name (UnName), the node in which they are located at (UnNode), the type of plant (UnPlant), the heat rate (UnHRT), the online and retirements years of the unit (UnOnline, UnRetire), and the generating capacity (UnGC). Additionally, units are assigned an outage rate (UnOR), a fixed cost (UnUOFMC), and a variable cost (UnUOMC). The units may be flagged as “industrial” (UnCogen), meaning it is self-generating and does not provide generation to the electric grid. Units may also be flagged as “must run” (UnMustRun), meaning the unit always runs.

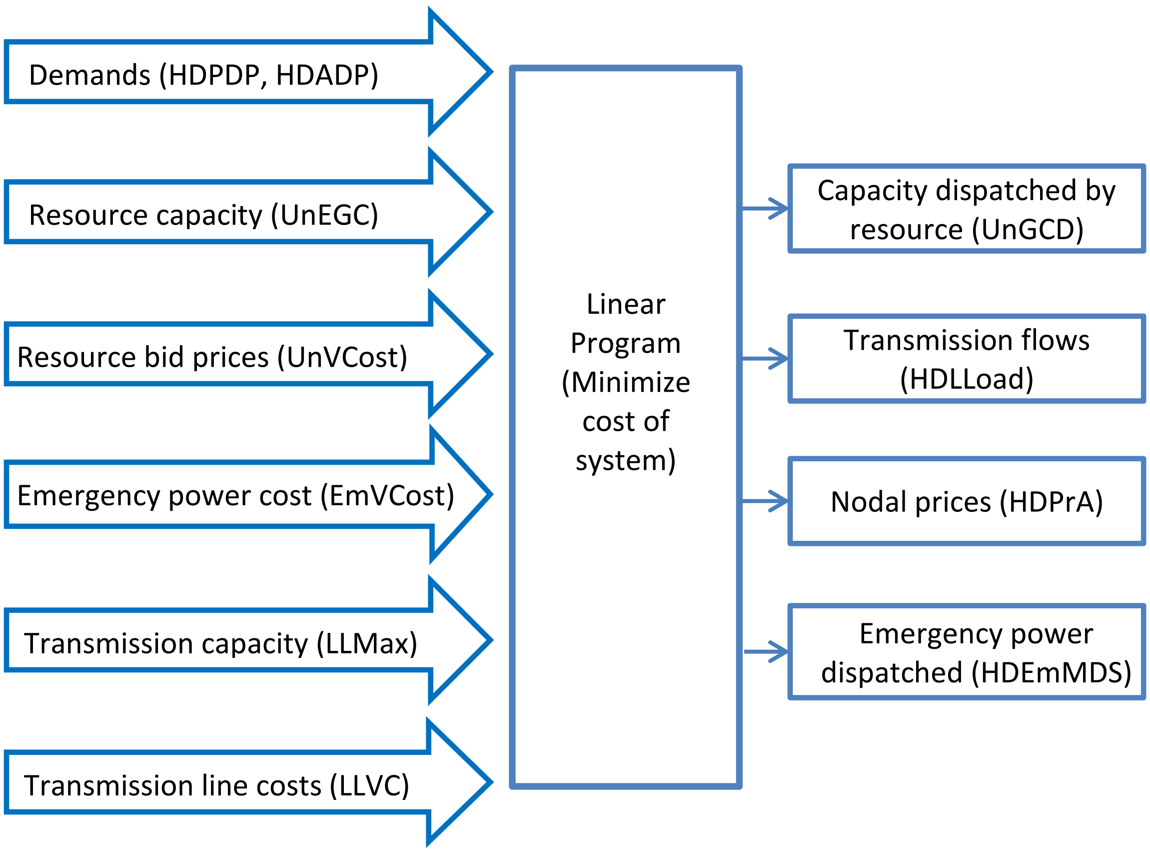
Linear Program Specifications

Each of the electric generating unit and transmission network inputs described above is used to find the optimal solution of generation, flows, and the resulting nodal prices. The generating capacity of the individual units and the cost of the units are translated into an amount of unit capacity available and a bid price by node, month, and time period. The entire geographic area of the model is dispatched as a single system each year. Figure 25 illustrates the inputs to and outputs from the LP.

The LP is solved for a single hour of each time period, month, and year of the simulation and includes all load and generation centers (nodes) in the model. The number and definition of the time periods and months may vary across model versions. The standard representation of months consists of two seasons – summer and winter. The standard number of time periods (or time slices) is six – peak, near peak, high intermediate, low intermediate, high base load, and low base load.

The model dispatches one hour with the goal typically being to meet the average demand (HDADP) for that time period at the lowest cost. For that hour, each node has a load, an amount of capacity available that its units can generate, and a cost of generating each unit. The nodes are part of a transmission system which takes into account the transmission constraints, efficiencies, and costs. The objective function of the LP minimizes the cost of the system to meet the demand at each node within the limitations of the capacity constraints. Units having the same costs are aggregated and represented as a single unit for dispatch. The aggregated units make up the total generating capacity of a node for that time period.

Figure 25. Linear Program Inputs and Outputs



The LP must determine the optimal mix to meet total demand at a single node. If there were not enough generating capacity available at that node, then no LP solution would exist for the entire system. To ensure that the objective function solves and provides outputs to the model, each node is assigned the potential to produce emergency back-up power (EmEGA) with no capacity limit. Emergency power does not generate from any specified physical electric units, but it can provide power to its own node if required. Emergency power prices are typically set much higher than generating costs of physical electric units. The resulting emergency power is used as a check on the model results – high emergency power indicates an imbalance in the system which should be investigated.

The **objective function** of the LP minimizes the cost of the system, where the system cost is defined as the sum of capacity dispatched (UnGCD) times unit bid prices (UnVCost), transmission flows (HDLLoad) times transmission costs (LLVC), and emergency power (HDEmMDS) times emergency power costs (HDEmVC). The inputs in this objective function are bid prices (UnVCost), transmission costs (LLVC), and emergency power costs (HDEmVC), and the variables being solved for are capacity dispatched (UnGCD), transmission flows (HDLLoad), and emergency generation (EmEGA).

This optimal solution is subject to a **generation balance constraint** meaning that, at each node, the amount of generation dispatched at or sent to the node minus the electricity sent from the node to another node must meet the demand for electricity at the given node. Since each transmission line has its own efficiency rating (LLEff), the line efficiency ratings are applied to the flows to account for line losses. Therefore generation balance constraint is put in the model as the sum of the generation dispatched at the node (UnGCD), transmission inflows to the node (HDLLoadin), and emergency power on the node (EmEGA) minus transmission line outflows from the node (HDLLoadout) must be great enough to meet the node's peak demand during peak time periods and average demand during non-peak time periods (HDPDP, HDADP), excluding cogeneration demands.

The optimal solution is subject to a **transmission constraint** which is the maximum flow (LLMax), in megawatts, on the line that can be run at any one time between two nodes. Transmission lines may have a requirement of a minimum level of flow between each node (LLMin), or there also may be loading of the transmission lines specified exogenously due to specific knowledge of a given transmission line (HDXLoad). The LP objective function is subject to the transmission constraint that the transmission flows on a given line must be less than or equal to the maximum capacity (LLMax) and it must be greater than or equal to the exogenous loading (HDXLoad).

The optimal solution is subject to a **capacity availability constraint**. The potential generating capacity at each node is the summation of the effective generating capacities (UnEGC) of the individual units. Generating units do not run all of the time, so they are given an outage rate (UnOR) to set the minimum amount of time that the unit must spend offline. Some renewable plant types have an additional constraint, as their "fuel sources" have limitations on when they are available. These units are given an effective generating capacity (UnEGC, XUnEGC) to take into account the restrictions on their availability. The capacity availability constraint requires the generation dispatched (UnGCD) to be less than or equal to the effective generating capacity of the units (UnEGC).

Below, Figure 27 is a summary of the objective function and its constraints in equation form.

Figure 26 - Linear Program objective function and constraints

	*The **objective function** of the LP is to minimize the value of*
LP objective function	Cost of Production = (∑ Capacity Dispatched (UnGCD) * Bid Price (UnVCost)) + (∑ Transmission Flow (HDLLoad) * Transmission Cost (LLVC) + (∑ Emergency Power (HDEmMDS) * Emergency Cost (HDEmVC)
	Subject to the following constraints:
Generation balance constraint	1. Nodal capacity dispatched (UnGCD) + transmission inflows $(HDLLoad_{in})$*Line efficiency (LLEff) – transmission outflows $(HDLLoad_{out})$*Line efficiency (LLEff) + Emergency power (HDEmMDS) >= Nodal Demand (HDPDP, HDADP)
Transmission constraint	2. Transmission flow (HDLLoad) <= Maximum transmission line limit (LLMax) Transmission flow (HDLLoad) >= Exogenous flows (HDXLoad)
Capacity availability constraint	3. Unit capacity dispatched (UnGCD) <= Unit capacity available (UnEGC)

Inputs to the Linear Program

The inputs to the LP include the following:

- system demands
- unit capacity available
- unit bid prices
- transmission line capacity and costs
- emergency power capacity and costs

Before being sent to the LP, each of these inputs is split by node, month, and time period, and is adjusted to incorporate differences in dispatching assumptions among the different types of generating plants. The standard plant types available for dispatch in the model include fossil-fueled units (gas/oil peaking, gas/oil combined cycle, gas/oil steam, and coal), nuclear plants, hydroelectric plants (base hydro, peak hydro, and pumped-storage hydro), and other renewable plant types (such as small hydro, wind, solar, geothermal, and biofuels).

Input to LP #1

System Demands: Peak and average demand (HDPDP, HDADP) provided by node, month, and time period are used as inputs to the LP and were outputs from the demand module. These demands represent the total electricity demand at each node excluding cogeneration.

Demand is increased to account for recharging pumped hydro units

Before being sent to the LP, the system demands are adjusted to account for any units that require additional electricity for recharging. The storage technology represented in ENERGY 2020 that requires recharging is pumped-storage hydro, referred to as pumped hydro in the model. Pumped-storage hydroelectricity is able to store energy for use during high-peak time periods by pumping water from a lower elevation reservoir to a higher elevation. The pumping process uses electricity to restore its water supply. The model (in procedure *RechargingRequirements*) keeps track of the electricity generated by storage technologies for time periods one through five. Then in time period six (the lowest load off-peak time period), additional demand requirements are added to the average system demand (HDADP) to account for restoring the pumped hydro units (in procedure *IncreaseLoadsForRecharging*) which are then available to run as any other unit, whenever it is cost effective to do so when compared to the market price.

Input to LP #2

Unit Capacity Available: Each generating unit is assigned an exogenously-specified capacity (UnGC) on a given node. To determine the amount of capacity available for dispatch (UnEGC), the unit capacity is derated, or lowered, based on unit outage rates before it is bid into the system. For most units, the full derated capacity is bid into the system. However, some exceptions exist for plant types having limitations on capacity or alternative dispatching assumptions. In these cases, the capacity available may vary across time periods. The three plant types in which there are limiting factors include peak hydro, pumped hydro, and intermittent resources, such as wind.

Peak hydro is allocated to peak time periods first

Peak Hydro: A peak hydro facility is one which is able to store water and can vary its generation through the day, month, and possibly year. It might also be called storage hydro. These are treated differently than base hydro facilities which are essentially "run-of-the-river" and cannot vary their generation. A base hydro facility generates whenever there is water. Peak hydro units, having flexible storage, are bid to maximize the water used during peak periods and minimize water "spilled" during off peak hours. Water is moved between hours and seasons. Available capacity (water) is allocated first to the peak time periods during the year. These peak time periods are determined based on annual load duration curves created for each node. The adjustments to available capacity for peak hydro units are done in procedure *AllocatePeakHydroAvailability.*

Pumped hydro is set to zero in off-peak hours for recharging

Pumped Hydro (storage units requiring recharging): Pumped-storage hydroelectricity is able to store energy for use during high-peak time periods by pumping water from a lower elevation reservoir to a higher elevation. The pumping process uses electricity to restore its water supply. During time period six (lowest load off-peak time period), pumped hydro units are restored so their available capacity (UnEGC) is set to zero.

Wind optionally can be assigned to off-peak periods and can be assigned reserves

Intermittent Resources (Wind): The treatment of wind units varies, but one option is to assign available capacity of wind units only to off-peak periods to approximate their intermittent generation. Another optional routine exists to simulate the required reserves to back up the intermittent resources. If reserve switches (UnRSwitch) are set within a policy, then the model will force specific units to supply reserves for intermittent resources, such as wind. The switch is turned off by default; however, this feature is available. Adjustments are made to the unit bids of intermittent units and to the effective generating capacity of both base load and wind units to force intermittent resources to be dispatched if there are enough reserves and to force the reserves to be dispatched if there are not enough reserves (procedure *ReserveUnitsAvailabilityAndBids).*

Input to LP #3

Unit Bid Prices: There are options to be able to select the method used to calculate a bid price (UnVCost) in the model. These options are specified using a switch (BlkSw) with the default being equal to one. As a default, this bid price is based on a fraction of fixed costs (UnAFC) and variable costs (UnAVC). The fractions of fixed and variables costs (HDFCFr, HDVCFr) are specified exogenously. The bid price additionally assumes a 75% capacity factor applied to the fixed costs.

Most units are bid in at their marginal cost. Some units, such as nuclear, may have a reported fuel cost which overstates their marginal costs. These units can be bid at less than their marginal costs. Fixed cost may also be included in the bid, if desired. Bids can vary by period.

The bid price is overwritten for units designated as must-run (UnMustRun=1). Must-run units are user-specified and are the exception, as they are prioritized to always run. The other units then may compete based on their availability and price. To ensure the must-run unit is dispatched, they are assigned a bid price slightly less than the bid price.

Input to LP #4

Transmission line capacity and costs: Transmission line constraints (LLMax) are an exogenous input to the model. The transmission costs (LLVC) are also an exogenous input. Transmission flows are a function of the dispatch algorithm; however exogenous “contract flows” can be added to force the flow of electricity between specific nodes. This may be needed when significant amount of storage hydro is available since the allocation of the water includes consideration of “contract flows”.

Input to LP #5

Emergency power capacity and cost: Emergency power is used in the dispatch algorithm if the node including transmission flows is insufficient to meet nodal demands. The capacity available for emergency power (HDEmGC) is unlimited. The bid price for emergency power on a given node is assigned a slightly larger price than the minimum unit bid price at that node. Emergency power bid prices are higher in order to ensure that emergency power is only dispatched if there is a capacity shortfall.

Linear Programming solution

Once the LP solves for the model, it provides two solutions for each entity in the equation. Each aggregated unit, transmission line, and emergency power generator has a primal and dual solution. The non-zero values of the primal solution for a single transmission line represent the capacity and generation dispatched provided by the specified resources from node “A” to “B” (UnGCD, UnEG, and EmEGA). If the primal solution for a resource is zero, then that resource did not run in the specified time period. If the primal solution for a single transmission line from a node “A” to a node “B” is zero, then for that hour, no transmission was sent across the transmission line in the specified direction.

The price of generation at a node is determined using the dual solution. Comparing the most expensive unit at a node to the dual solution for a unit that did not run at that node indicates the marginal price at that node. When the primal solution is zero, then a dual solution exists. For a given resource, the dual solution value corresponds to the price (in $/MWh) at that node that generation must increase in order for this unit to be turned on. For transmission from node A to B, the dual solution indicates the price that generation must increase at node “B”, before node “A” sends generation across that transmission line.

Imports and Exports

Electricity imports and exports are obtained from the transmission flows (HDLLoad) output from the LP. Procedure *Flows* stores the transmission flows between the US and Canada nodes obtained from the LP for imports (ExpPurchases) and exports (ExpSales). Imports and exports can be specified exogenously (using the variable HDXLoad) for instances where there are known levels of imports or exports, such as through contracts. The exogenously-specified values are added to the flows determined by the LP.

Cogeneration

Cogeneration is not included as part of the electric generation dispatch module. The LP determines the optimal mix of electric utility generating units only and is designed to meet the system energy demands excluding cogeneration (HDADP, HDPDP).

Submodule Procedures

The procedures used to simulate electric generation dispatch are all housed within the *EDispatch.src* file and called from the *DispatchElectricity* procedure. The core of the electric generation dispatch submodule is the linear programming algorithm. All the procedures within this submodule perform one of three functions – 1) prepare inputs to the LP, 2) execute and solve the LP, or 3) process outputs from the LP.

The procedures that make up *DispatchElectricity* and their order of execution are shown in Figure 28.

The procedures that prepare the inputs to the LP assign values and make adjustments to system demand, transmission costs, unit bids, and resource capacity available, and they are listed below.

Prepare inputs to LP

- *UnitCosts*
- *TransmissionCosts*
- *AllocatePeakHydroAvailability*
- *InitializeEnergyForStorage*
- *IncreaseLoadsForRecharging*
- *UnitCapacityAvailability*
- *EmergencyPowerAvailability*
- *UnitBids*
- *ReserveUnitsAvailabilityAndBids*

Figure 27. Procedure DispatchElectricity in EDispatch.src

Preparing inputs to LP

Solving the LP equation

Processing LP results

```
Do Until Pollution Constraint Met
        UnitCosts
        TransmissionCosts
        AllocatePeakHydroAvailability
    InitializeEnergyForStorage
    For Each Month (Season) and Time Period
        IncreaseLoadsForRecharging
        UnitCapacityAvailability
        UnitBids
        ReserveUnits (Optional)
        RunLPForDispatch
        RechargingRequirements
    End Month and Time Period Loop
        GenerationAverage
        PutGenerationData
        PollutionForPolicy
        ConstrainAvailabilityBasedOnPollution
End Do until Pollution Constraint Met
OutputsFromDispatch
```

The procedure that executes the linear programming algorithm and dispatches the unit generation is:

Execute LP

- *RunLPForDispatch*.

The procedures that prepare that process LP results are listed below.

Process LP results

- *RechargingRequirements*
- *GenerationAverage*
- *PutGenerationData*
- *PollutionForPolicy*
- *ConstrainAvailabilityBasedOnPollution*
- *OutputsFromDispatch*

Table 39 provides a summary description of each of the procedures called from the *DispatchElectricity*, and the key outputs are listed as well. Further details on each of these procedures can be found in the subsequent sections.

Table 39. Description of Procedures within Generation Dispatch

Procedure Description	Key Outputs
1. UnitCosts Calculates unit fuel prices (UnFP) based on the previous year's prices then uses fuel prices to calculate unit variable costs (UnAVC). Also calculates other unit financial variables, such as net assets (UnNA), depreciation (UnSLDPR), and unit fixed costs (UnAFC). Sets the variable costs (UnAVC) of must-run plants to zero to ensure they will be dispatched.	Unit costs (UnAVC, UnAFC, UnNA, UnSLDPR) which are used as input to *UnitBids* procedure.
2. TransmissionCosts Gets transmission line costs (XLLVC) and adjusts for emissions tax rates (LLPoTxR) if applicable. The transmission line costs are then used directly as input to the *RunLPForDispatch* procedure.	Transmission line costs (LLVC)
3. AllocatePeakHydroAvailability Allocates peak hydro plants by prioritizing available capacity (UnGC) to annual peak time periods then to lower load hours. Uses nodal demand (HDPDP) to create annual load duration curve for identifying annual peak time periods. Distributes this available capacity (UnEGC) assigned to annual peak periods back to model's definitions of months and time periods for dispatch.	Peak hydro effective generating capacity ($UnEGC_{PeakHydro}$)

Procedure Description	Key Outputs
4. IncreaseLoadsForRecharging Adjusts nodal demand (HDADP) in low load hours for restoring energy needed to charge pumped-storage hydro facilities. Also saves the amount of electricity required to recharge the storage technologies (StorEnergy). The revised nodal demands are used directly as input to the linear program in *RunLPForDispatch*. The electricity required (StorEnergy) is saved as output, but not used.	Average demand in low load hours (HDADP) Electricity required to recharge storage technologies (StorEnergy)
5. UnitCapacityAvailability Determines capacity available (UnEGC) for all units except peak hydro units which were assigned in *AllocatePeakHydroAvailability*, constrains the available capacity ($UnEGC_{Storage}$) for storage units in low load time periods, assigns capacity available for emergency power (HDEmGC), and overwrites calculated availability with exogenous unit availability (XUnEGC) if specified.	Capacity available (UnEGC) Emergency power available (HDEmGC)
6. UnitBids Calculates a bid price (UnVCost) for each of the units based on a fraction of fixed and variable costs (HDFCFr, HDVCFr) which are specified exogenously. Must run units are assigned a bid price slightly less than the bid price of other units to ensure those units are chosen for dispatch. Bid prices for emergency power (HDEmVC) are calculated as well. The bid price for emergency power is assigned a higher price than the minimum unit bid price to ensure emergency power is not dispatched unless there is a capacity shortage. These bid prices are direct inputs to the linear programming algorithm in *RunLPForDispatch*.	Unit bid price/unit variable cost (UnVCost) Emergency power variable cost (HDEmVC)
7. ReserveUnits (Optional) This procedure is only executed for policy analysis, and the equations are dependent upon a renewable switch being turned on to force specific units to supply reserve requirements (UnRSwitch eq 1) for intermittent resources, such as wind. It is also dependent on the assignment of reserves available (UnRAv gt 0). If the renewable switch is turned on, then this procedure determines whether or not there are enough reserves available for the intermittent resources to be dispatched. It forces the reserves on when needed and forces the intermittent resources on when reserve requirements are met.	Reserves needed (ResNeed) Capacity available and bid prices ($UnEGC_{Reserves}$, $UnEGC_{Wind}$, $UnVCost_{Wind}$)

Procedure Description	Key Outputs
8. RunLPForDispatch Determines the optimal mix of generation (UnEG) and transmission flows (HDLLoad) that meets nodal energy demands by minimizing overall costs of the system. Key inputs to this procedure include nodal demands (HDPDP, HDADP), unit bid prices (UnVCost), transmission line costs (LLVC), transmission limits (LLMax), and capacity available/effective generating capacity (UnEGC). A linear programming (LP) algorithm is used for the optimization with the constraints of meeting nodal demand, staying within transmission line limit constraints, and using the capacity available. Emergency power (HDEmGC) is available as a resource at each node at a cost higher than other resources (HDEmVC) to ensure that the LP solves.	Unit capacity and generation dispatched (UnGCD, UnEG), Transmission flows (HDLLoad), Nodal prices (HDPrA), Emergency capacity and generation dispatched (HDEmMDS, EmEGA)
9. RechargingRequirements This procedure accumulates the electricity generated by storage technologies for time periods one through five (peak and intermediate time periods, not low-load hours).	Energy required to recharge storage technologies (StorEnergy); Electricity generated by storage technologies (StorEG)
10. GenerationAverage Calculates average across dispatch iterations. There currently is only one iteration, so this procedure is no longer needed.	Generation by unit, time period, and month (UnEGTM)
11. PutGenerationData Simply writes the generation variables to disk (UnEGTM, StorEG, and StorEnergy). Need to revise this procedure to put the write statements with the equations.	Procedure needs revised.
12. PollutionForPolicy Calculates emissions based on generation dispatched and saves to policy variable.	Emissions from generation dispatched (PolGHG)
13. ConstrainAvailabilityBasedOnPollution This procedure is used for policies in which a constraint on emissions exists. If there is a constraint, then the variable PolAvFactor is adjusted and the dispatch is re-executed.	Availability Factor due to pollution constraint (PolAvFactor)

Procedure Description	Key Outputs
14. OutputsFromDispatch Calculates outputs resulting from dispatch, such as generation totaled across different sets, unit costs, stranded investments for retired units, imports and exports.	Unit costs, imports, exports

Procedure UnitCosts

The *UnitsCosts* procedure reads in fuel costs (FP) and unit costs. Unit fuel prices (UnFP) are calculated based on the previous-year's sector-level delivered fuel prices (FP) determined in the Electric Pricing Submodule. These unit prices (UnFP) are used to calculate a unit-level average variable cost (UnAVC). Net assets (UnNA), depreciation (UnSLDPR), fixed costs (UnAFC) of the units are also calculated.

The values of the variables calculated in this *UnitCosts* procedure are used to calculate unit bid prices in the *UnitBids* procedure which are ultimately sent to the linear program for dispatch.

The equations for each of these outputs – unit fuel price, net assets, depreciation, unit average fixed costs, and unit average variable costs respectively are listed below.

Key Equations: UnitsCosts

Unit fuel price:

UnFP = FP*UnFlFr*FlPrMap

Unit fuel price of nuclear:

$UnFP_{Nuclear}$=XUFC*Infla/UnHRT*1000

Unit net assets:

UnNA=UnNA+UnCWGA-UnSLDPR+UnRCGA

Unit depreciation rate:

UnSLDPR=UnNA*DPRSL

Unit fixed Costs:

UnAFC = (UnNA*CCR+UnSLDPR)/UnGC*1000+UnUFOMC*Infla+UnRCOM

Unit variable costs:

UnAVC = UnFP*UnHRt/1000+UnUOMC*Infla+UnPoTR+UnPoTRExo*Infla

Table 40 lists the variable names and definitions of the key input and output variables from the *UnitCosts* procedure.

Table 40: UnitCosts Procedure - Input and Output Variables

***UnitCosts* Inputs and Outputs**
Key inputs
CCR (Plant, GenCo, Year) = Capital Charge Rate (1/Yr)
DPRSL (GenCo, Year) = Straight Line Depreciation Rate (1/Yr)
FlPrMap (FuelEP, Prices) = FuelEP to Prices Map for Electric Generation
FP (Prices, Area, Year) = Delivered Fuel Price ($/mmBtu)
Infla (Year) = Inflation Index ($/$)
UnFlFr (Unit, FuelEP, Year) = Unit Fuel Fraction (Btu/Btu)
UnGC (Unit, Year) = Unit Generating Capacity (MW)
UnHRt (Unit, Year) = Heat rate (btu/kWh)
UnPoTRExo (Unit, Year) = Exogenous Pollution Tax Rate (Real$/MWh)
UnPoTR (Unit, Year) = Pollution Tax Rate ($/MWh)
UnRCOM (Unit, Year) = Emission Reduction O&M Costs (M$)
UnUFOMC (Unit, Year) = Fixed O&M Costs (Real $/KW)
UnUOMC (Unit, Year) = Variable O&M Costs (Real $/MWh)
XUFCPlant (GenCo, Year) = Unit Fuel Cost ($/MWh)
Key outputs
UnAFC (Unit, Year) = Average Fixed Costs of Unit ($/KW)
UnAVC (Unit, Year) = Average Variable Costs of Unit ($/MWh)
UnFP (Unit, Year) = Fuel Price of Unit ($/mmBtu)
UnNA (Unit, Year) = Net Asset Value of Unit (M$)
UnSLDPR (Unit, Year) = Depreciation of Unit (M$/Yr)

Procedure TransmissionCosts

The *TransmissionCosts* procedure reads in transmission line costs and adjusts for emissions tax rates if applicable. The costs calculated in this procedure (LLVC) are input to the linear program in *RunLPForDispatch* for calculation of the overall system cost of dispatch.

There is only equation used in *TransmissionCosts* which adjusts exogenous transmission costs with any pollution costs or taxes that may exist. The equation is shown below.

Key Equation: TransmissionCosts

<u>*Transmission costs:*</u>

$$LLVC = (XLLVC + \sum_{Mkt} LLPoTxR + LLPoTxRExo) * Infla$$

Table 41 lists the variable names and definitions of the key input and output variables.

Table 41: TransmissionCosts Procedure - Inputs and Output Variables

***TransmissionCosts* Inputs and Outputs**
Key inputs XLLVC (Node, NodeX, Year) = Transmission rate ($/MWh) Infla (Year) = Inflation Index ($/$) LLPoTxR (Node, NodeX, Market, Year) = Pollution Costs for Transmission ($/MW) UnPoTR (Unit, Year) = Pollution Tax Rate ($/MWh) **Key outputs** LLVC(Node, NodeX, Year)   Transmission Rate ($/MWh)

Procedure AllocatePeakHydroAvailability

Peak hydro units are able to store energy for use during peak time periods. The *AllocatePeakHydroAvailability* procedure simulates an optimal allocation of available water by allocating the capacity of the peak hydro units to peak time periods first then to the base load time periods.

The allocation is done by creating an annual load duration curve for each node as well as multiple time slices (currently set to 12 time slices from the highest peak to the lowest load time period). The capacity and energy is then be mapped back to the months (seasons) and time periods defined for dispatch (by default six time periods).

Inputs to the procedure include unit generating capacity (UnGC), own use rate for generating capacity (UnOURGC), unit energy availability factor (UnEAF), and peak load by node, time period, month, and year (HDPDP).

The key output from this procedure is the effective generation capacity (UnEGC) of peak hydro units which is used as input to the linear program in *RunLPForDispatch*. Table 42 summarizes the variable names and definitions of the key input and output variables.

Table 42: Inputs and Output Variables - AllocatePeakHydroAvailability

***AllocatePeakHydroAvailability* Inputs and Outputs**
Key inputs HDPDP (Node, TimeP, Month, Year) = Peak Load in Interval (MW) UnGC (Unit, Year) = Unit Generating Capacity (MW) UnOURGC (Unit, Year) = Own Use Rate for Generating Capacity (MW/MW) UnEAF (Unit, Month, Year) = Energy Availability Factor (MWh/MWh) **Key output** $UnEGC_{Unit,TimeP,Month,Year}$ = Effective Generating Capacity (MW)

Procedure IncreaseLoadsForRecharging

Storage technologies, such as pumped storage hydro or batteries, require energy to be recharged. Currently, the only storage technology modeled in ENERGY 2020 is pumped hydro. The pumped hydro units are restored or recharged during off-peak hours and are available to run as any other unit, or in other words, whenever it is cost effective to do so compared to the market price.

The purpose of *IncreaseLoadsForRecharging* is to increase energy demand (HDADP) during the low load hours (time period six) to simulate the pumped hydro units' demand for energy required (StorEnergy) for replenishing hydro storage. The adjusted demands (HDADP) are ultimately used as input to the linear program in *RunLPForDispatch*.

This procedure is only called for time period six after time periods one through five have been dispatched. The generation dispatched in time periods one through five from storage units is accumulated in the *RechargingRequirements* procedure after the LP execution and stored (StorEG).

Because *IncreaseLoadsForRecharging* is called after time periods one through five have been dispatched, the amount of energy used by the pumped hydro units is known and in time period six, it is replenished. The additional energy needed to recharge the pumped storage hydro units (StorEnergy) is calculated by dividing the storage units' generation (StorEG) by an exogenous recharging efficiency (StorEFF). An adjustment is then made to the average nodal demand (HDADP) for time period six by adding the additional energy needed to recharge storage technologies (StorEnergy).

The key equations used in IncreaseLoadsForRecharging are listed below.

Key Equations: IncreaseLoadsForRecharging

Storage energy used:

StorEnergy=StorEG/StorEff

Average energy demand:

HDADP=HDADP+StorEnergy/HDHours*1000

The outputs of this procedure include the amount of storage energy that was needed (StorEnergy) and a revised average nodal demand (HDADP) in time period six (low load hours). The storage energy needed (StorEnergy) is an output but not used by any other procedures in ENERGY 2020. The adjusted nodal demands (HDADP) are used as input to the linear program in *RunLPForDispatch*. Table 43 summarizes the variable names and definitions of the key input and output variables.

Table 43: Input and Output Variables - IncreaseLoadsForRecharging

IncreaseLoadsForRecharging Inputs and Outputs
Key inputs HDHours (TimeP6, Month) =Number of Hours in the Interval (Hours) StorEff (Node, Month, Year) = Recharging Efficiency of Storage Techs (kWh/kWh) HDADP (Node, TimeP6, Month, Year) = Average Load in Interval (MW) StorEG (Node, Month, Year) = Electricity Generated from Storage Techs (GWh) **Key outputs** HDADP (Node, TimeP, Month, Year) = Average Load in Interval (MW) StorEnergy (Node, Month, Year) = Electricity Required to Recharge Storage Techs (GWh) HDHours (TimeP6, Month) =Number of Hours in the Interval (Hours) StorEff (Node, Month, Year) = Recharging Efficiency of Storage Techs (kWh/kWh) HDADP (Node, TimeP6, Month, Year) = Average Load in Interval (MW) StorEG (Node, Month, Year) = Electricity Generated from Storage Techs (GWh)

Procedure UnitCapacityAvailability

The *UnitCapacityAvailability* procedure assigns a value for effective generating capacity, or the amount each unit bids into the system by node, time period, and month/season for each of the units of all plant types except peak hydro which previously was assigned in *AllocatePeakHydroAvailability*.

UnitCapacityAvailability performs four functions. First it calculates effective generating capacity. The capacity available or capacity bid into the market (UnEGC) is calculated using the unit capacity (UnGC) derated by the outage rates (UnOR, UnOOR) and an availability factor (AvFactor) times a bid fraction (HDGCFr).

Second, this procedure constrains the available capacity for storage units (which are energy limited) by using an energy availability factor ($UnEAv_{Storage}$) during different time periods. The energy availability factor is calculated ($UnEAv_{Storage}$) during peak time periods as the unit capacity (UnGC) times the unit's energy availability factor (UnEAF) times the hours (HDHours) in the season. During non-peak periods, the amount of energy available ($UnEAv_{Storage}$) is energy available in the previous time period minus the energy dispatched (UnEG) in the previous time period. Time period one (peak) is dispatched first, so when the equations for time periods two through six are executed, the dispatch for the previous periods are known.

The amount of energy actually bid (UnEGC) is specified as the bid fraction (HDGCFr) constrained by the energy available (UnEAV).

Third, *UnitCapacityAvailability* assigns a capacity available value to emergency power available (HDEmGC). Emergency power is assumed to be available at each node. This procedure assigns the emergency power available (HDEmGC) to be the peak load at each node, time period, and month (LDCMS). Having the emergency power available ensures there will always be enough capacity at each node for the LP to solve.

Finally, if any units have exogenously-specified capacity (XUnEGC), then the calculated effective capacities (UnEGC) are replaced by those values.

The key equations in the *UnitCapacityAvailability* procedure are listed below.

Key Equations: *UnitCapacity Availability*

Effective generating capacity:

$$UnEGC=UnGC*(1-UnOURGC)*(1-UnOR)*(1-UnOOR)*AvFactor *PolAvFactor*HDGCFr$$

Energy availability of storage units:

$$UnEAv_{Peak}=UnGC*(1-UnOUREG)*UnEAF*(1-UnOOR)*Hours/1000$$

$$UnEAV_{Non\text{-}Peak}=(UnEAV_{TimeP\text{-}1})-(UnEG_{TimeP\text{-}1})$$

Effective generating capacity of storage units:

$$UnEGC_{Storage}=Minimum\ (UnEGC_{Storage}*HDGCFr,\ UnEAv_{Storage}/HDHours*1000)$$

Capacity available for emergency power:

$$HDEmGC=\sum_{ReCo}LDCMS$$

The key outputs are (UnEGC) for all units except peak hydro and the amount of available emergency power (HDEmGC). Table 44 summarizes the variable names and definitions of the key input and output variables.

Table 44: Input and Output Variables - UnitCapacityAvailability

UnitCapacityAvailability Inputs and Outputs
Key inputs
AvFactor (Plant, TimeP, Month, Area, Year) =Availability Factor (MW/MW)
HDGCFr (Plant, GenCo, Node, TimeP, Month, Year) = Fraction of Available Generating Capacity Bid (MW/MW)
HDHours (TimeP, Month) = Number of Hours in Interval (Hours)
Hours (Month) = Hours per Monthly Period (Hours)
LdCMS (Day, Month, Node, ReCo, Year) = Marketer System Load Curve (MW)
PolAvFactor (Plant, Area, Year) = Availability Factor from Pollution Constraint (MW/MW)
UnEAV (Unit, TimeP. Month, Year) = Energy Availability Factor (MWh/MWh)
UnOURGC (Unit, Year) = Own Use Rate for Generating Capacity (MW/MW)

UnitCapacityAvailability Inputs and Outputs
UnOR (Unit, Year) = Outage Rate (MW/MW)
UnOOR (Unit, Year) = Operational Outage Rate (MW/MW)
XUnEGC (Unit, TimeP, Month, Year) = Exogenous Effective Generating Capacity (MW)
Key outputs
UnEGC (Unit, TimeP, Month, Year) = Effective Generating Capacity (MW)
HDEmGC (Node, Month, Year) = Emergency Power Available (MW)

Procedure UnitBids

The *UnitBids* procedure calculates a bid price (UnVCost) for each of the units. As a default, the bid price is based on a fraction of fixed and variable costs (HDFCFr, HDVCFr) which are specified exogenously. There are other options for how to calculate a bid price, and those options are specified by changing a switch (BlkSw), where the default is equal to one. Must run units are assigned a bid price slightly less than the bid price of other units to ensure the linear program will choose those units for dispatch. This procedure also calculates a bid price for emergency power (HDEmVC) at each node. The bid price for emergency power on a given node is assigned a slightly larger price than the minimum unit bid price at that node. Emergency power bid prices are higher in order to ensure that emergency power is only dispatched if there is a capacity shortfall.

By default, the bid prices (UnVCost) are equal to fixed costs (UnAFC) assuming a 75% capacity factor times an exogenously-specified fraction of fixed costs (HDFCFr) plus variables costs (UnAVC) times an exogenously-specified fraction of variable costs (HDVCFr) plus a very small random number to break ties. If a pollution tax rate is specified (UnPoTR), this rate is added onto the bid price as well.

Must Run units (UnMustRun=1) are bid in at a little bit less than the minimum bid of all the other units to ensure that they are the first dispatched.

Emergency Power is assumed to be available at each node at a cost (HDEmVC) greater than any of the local bids (the maximum of the unit bids plus ten (UnVCost + 10), the marginal cost of electricity for peaking units plus ten (MCE_{Peak} + 10), or an exogenously-specified emergency power cost (XEmgVCost).

The key equations used in the *UnitBids* procedure are as follows.

Key Equations:
UnitBids

Bid price of the units:

UnVCost = UnAVC*HDVCFr + (UnAFC/(8760*.75)*1000)*HDFCFr +
abs(RanNum)/10000 + UnPoTR

Bid price for must-run units:

MinBid=UnVCostMinimum

$UnVCost_{MustRun}$=MinBid-0.001

Bid price for emergency power:

HDEmVC=Maximum (XEmgVCost or UnVCost+10.00 or MCE_{Peak}+10.00)

Both the unit bid prices (UnVCost) and emergency power prices (HDEmVC) are used as direct inputs to the linear programming algorithm in the *RunLPForDispatch* procedure. Table 45 summarizes the variable names and definitions of the key input and output variables.

Table 45: Input and Output Variables - UnitBids

UnitBids Inputs and Outputs
Key inputs BlkSw (GenCo,Year) = Block Switch Indicating Method of Calculating Bids HDFCFr (Plant,GenCo,TimeP,Year) = Fraction of Fixed Costs Bid HDVCFr (Plant,GenCo,Node,TimeP,Month,Year) = Fraction of Variable Costs Bid UnAFC (Unit, Year) = Unit Average Fixed Costs ($/KW) UnAVC (Unit,Year) = Unit Average Variable Costs ($/MWh) UnMustRun (Unit,Year) = Must Run Switch (1=Must Run) UnPoTR (Unit,Year) = Pollution Tax Rate ($/MWh) XUnVCost (Unit,TimeP,Month,Year)= Exogenous Market Price Bid ($/MWh) **Key outputs** UnVCost (Unit,TimeP,Month,Year) = Bid Price of Power Offered to Spot Market ($/MWh) HDEmVC (Node,TimeP,Month,Year) = Dispatch Price for Emergency Power ($/MWh)

Procedure ReserveUnits

The *ReserveUnits* procedure is only executed for policy analysis, and the equations are dependent upon a renewable switch being turned on to force specific units to be a back-up supply for reserve requirements (UnRSwitch eq 1) for intermittent resources, such as wind. It is also dependent on the assignment of reserves available (UnRAv gt 0). If the renewable switch is turned on, then this procedure determines whether or not there are enough reserves available for the intermittent resources to be dispatched. It forces the reserves on when needed and forces the intermittent resources on when reserve requirements are met.

The *ReserveUnits* procedure is executed only during the low load time period (time period six) and determines the reserves that are needed and available for intermittent resources that require reserves, such as wind. At the point in the model execution when this procedure is called, time periods one through five have already been dispatched. The intermittent resources are only dispatched if there are enough reserves available. This procedure calculates whether or not there are enough reserves from base load units left by time period six to run the intermittent resources, such as wind. If there are enough reserves, the intermittent resources will be forced on by setting the unit bid price to be zero (UnVCost=0). If there are not enough reserves, then the intermittent resources will be forced off by setting the capacity available to be zero (UnEGC=0).

Table 46 summarizes the variable names and definitions of the key input and output variables.

Table 46: Input and Output Variables - ReserveUnits

ReserveUnits Inputs and Outputs
Key inputs UnRSwitch (Unit) = Switch for Units Forced to Supply Reserve Requirements (1=Yes) ExpUVCost (Month,Year) = Expected Spot Price for Low Load Hour Time Period ($/MWH) UnAVC (Unit,Year) = Average Variable Costs ($/MWh) UnEGC ($\text{Unit}_{\text{BaseLoad}}$,TimeP,Month,Year) = Effective Generating Capacity (MW) UnRAv (Unit) = Reserves Available (MW/MW) UnRRq (Unit) = Reserve Requirements (MW/MW) ResReq (Node,Month,Year) = Low Load Hour Reserve Requirements (MW) **Key outputs** UnEGC ($\text{Unit}_{\text{Wind}}$,TimeP,Month,Year) = Effective Generating Capacity (MW) UnVCost ($\text{Unit}_{\text{Wind}}$,TimeP,Month,Year) = Bid Price of Power Offered to Spot Market ($/MWh) UnResFlag (Unit,TimeP,Month,Year) = Flag to Indicate if Unit is Forced On to Provide Reserves (1=Yes) UnRVCost (Unit,Month)= Effective Cost of Reserves ($/MWH)

Procedure RunLPForDispatch

The *RunLPForDispatch* procedure is the heart of the electric generation dispatch submodule. Its purpose is to determine the optimal mix of generation that will meet the energy demand on each of the nodes by minimizing overall costs of the system. A linear programming (LP) algorithm is used to minimize the system costs subject to meeting nodal demand, transmission line limit constraints, and capacity availability constraints. Emergency power is available as a resource at each node to ensure that the LP solves.

The key inputs to this procedure and the source of those inputs include the following:

- nodal demands (HDPDP, HDADP) from the Demand Sector,
- unit bid prices (UnVCost) and emergency bids (HDEmVC) from *UnitBids*,
- unit capacity available or effective generating capacity (UnEGC) from *UnitCapacityAvailability* and *AllocatePeakHydroAvailability*,
- transmission costs (LLVC) from *TransmissionCosts*, and
- Transmission line limits (LLMax) which are exogenous inputs.

Outputs from this procedure include unit generation and capacity, transmission flows, and nodal prices.

- Capacity dispatched (UnGCD)
- Transmission flow (HDLLoad)
- Emergency power (HDEmMDS)
- Marginal prices (HDPrA)

The source code for the LP is housed in EGen5LP.src. The *RunLPForDispatch* procedure makes a call to *LPCtrl* inside EGen5LP.src to initiate the LP. The key procedures that make up LPCtrl include the following:

1. *AggregateDataForLP*: In order to reduce the number of variables and constraints in the Linear Program which will resolve the transmission constraints, the capacities and costs at each node are combined into aggregate units (UnAgg) with similar costs.
2. *WriteLPInputFile:* This procedure writes to a text file the objective function of the LP used as input to the LP.
3. *RunLP:* Executes the LP solver
4. *ReadLPOutputFile:* Reads the output file from the LP to retrieve generation, transmission flows, prices, and emergency power
5. *OutputLPData:* This procedure processes the aggregated outputs and splits the results into individual units.

As described in the methodology section, the objective function of the LP minimizes the cost of the system subject to generation balance, transmission, and capacity availability constraints.

LP Aggregation

In order to reduce the number of variables and constraints in the linear program, the capacities and costs at each node are combined into aggregate units (UnAgg) with near identical costs. Instead of all of the units in the model, these aggregated units are entered into the external LP solver program to cut down on calculation time. The individual units that make up each aggregated unit are kept track of before sending the aggregated units to the LP solver. The contribution of generating capacity of each unit to the aggregated sum is recorded to disaggregate the LP solution back to the unit level for use in ENERGY 2020.

The aggregation process starts for each node by sorting available units by costs (UnVCost) which are compared to determine whether or not to combine into an aggregate unit. This sorting and aggregating process is carried out by the model on a yearly basis.

In order for a unit to be combined into an aggregate, its cost (UnVCost) must either be less than 1.02 times the aggregate unit's cost (AgVCost) or less than the aggregates unit's cost + 0.001. If this criterion is met, then the effective generating capacity of the aggregate unit (AgEGC) is equal to its current capacity plus the capacity of the unit (UnEGC).

Once the LP has solved, the unit generating capacity dispatched is calculated for the individual units that made up the larger aggregate units. The unit generating capacity dispatched (UnGCD) is equal to the aggregate unit capacity dispatched (AgGCD) times the unit effective generating capacity (UnEGC) divided by the aggregate unit effective generating capacity (AgEGC). In other words, the model keeps track of each individual unit that makes up an aggregated unit. Once the LP has solved, it provides how much generation the aggregated unit provided. This information is used to calculate how much generation each of the individual units provided.

The actual generation of the individual units (UnEG) for that time period can then be calculated from the unit generating capacity dispatched (UnGCD) times the number of hours in the period (HDHours) divided by 1000 to convert MW to GWh.

Key equations in LP aggregation include:

Key Equations in RunLPForDispatch

*<u>Aggregated available capacity for units where (UnVCost < AgVCost * 1.02) or (UnVCost < AgVCost + 0.001)</u>*
AgEGC = AgEGC + UnEGC

<u>Unit generating capacity dispatched</u>
UnGCD = AgGCD * UnEGC / AgEGC

Unit generation dispatched

UnEG = UnGCD * HDHours / 1000

Table 47 summarizes the variable names and definitions of the key inputs and outputs from *RunLPForDispatch*.

Table 47: Input and Output Variables - RunLPForDispatch

RunLPForDispatch Inputs and Outputs
Key inputs
HDADP (Node,TimeP,Month,Year) = Average Load in Interval (MW)
HDPDP (Node,TimeP,Month,Year) = Peak Load in Interval (MW)
HDEmGC (Node,Month,Year) = Emergency Power Available (MW)
HDEmVC (Node,TimeP,Month,Year) = Emergency Power Dispatch Price ($/MWh)
LLMax (Node,NodeX) = Maximum Loading on Transmission Lines (MW)
LLVC (Node,NodeX) = Transmission Rate ($/MWh)
UnEGC (Unit,TimeP,Month,Year) = Effective Generating Capacity (MW)
UnVCost (Unit,TimeP,Month,Year) = Bid Price of Power Offered to Spot Market ($/MWh)
Key outputs
HDEmMDS (Node,TimeP,Month,Year) = Emergency Power Dispatched (MW)
EmEGA (Node,TimeP,Month,Year) = Emergency Generation (GWh)
UnGCD (Unit,TimeP,Month,Year) = Generating Capacity Dispatched (MW)
UnEG (Unit,TimeP,Month,Year) = Unit Generation (GWh)
HDLLoad (Node,NodeX,TimeP,Month,Year) = Loading on Transmission Lines (MW)
HDPrA (Node,TimeP,Month,Year) = Spot Market Marginal Price ($/MWh)

Procedure RechargingRequirements

This procedure accumulates the electricity generated by storage technologies (StorEG), such as pumped hydro, for time periods one through five (time period six represents low load hours for which storage technologies need recharging). Due to the looping nature of the submodule, the output of this procedure (StorEnergy) is used in the earlier procedure *IncreaseLoadsForRecharging* and increases the amount of energy demand by the amount of electricity that is required for recharging.

Key Equations for RechargingRequirements are as follows:

Key Equations in Recharging Requirements

Electricity generated from storage technologies:

StorEG=StorEG+UnEG, *accumulated across units with* UnStorage *equals* 1

<u>Electricity required to recharge storage technologies:</u>
StorEnergy=StorEnergy+UnEG/UnEffStorage, *accumulated across units with* UnStorage *equals* 1

Table 48 summarizes the variable names and definitions of the key inputs and outputs used in *RechargingRequirements*.

Table 48: Input and Output Variables - RechargingRequirements

RechargingRequirements Inputs and Outputs
Key inputs UnEffStorage (Unit) = Storage Efficiency (GWH/GWH) UnEG (Unit,TimeP,Month,Year) = Generation (GWH) UnStorage (Unit) = Storage Switch (1=Storage Unit) **Key outputs** StorEG (Node,Month,Year) = Electricity Generated from Storage Techs (GWh/Year) StorEnergy (Node,Month,Year) = Electricity Required to Recharge Storage Techs (GWh/Year)

Procedure PollutionForPolicy

This procedure is used for policies and calculates emissions based on generation dispatched then saves to policy variable (PolGHG).

PollutionForPolicy accumulates emissions using the equation below.

<u>GHG Emissions from dispatched generation:</u>
PolGHG=PolGHG+∑(UnEGTM*UnPOCGWh*PolConv), *accumulated across units*

Table 49 summarizes the variable names and definitions of the procedure's key inputs and outputs.

Table 49: Input and Output Variables - PollutionForPolicy

PollutionForPolicy Inputs and Outputs
Key inputs PolConv (Poll) = Pollution Conversion Factor (convert GHGs to eCO2) UnEGTM (Unit,TimeP,Month,Year) = Generation (GWH) UnPOCGWh (Unit,Poll,Year)= Pollution Coefficient (Tonnes/GWh) Key outputs PolGHG (Area,Year) = GHG Emissions from Dispatched Generation (Tonnes)

Procedure ConstrainAvailabilityBasedOnPollution

This procedure is used for policies in which a constraint on emissions exists. If there is a constraint, then the availability factor (PolAvFactor) is adjusted and the dispatch is re-executed. The model will re-execute generation dispatch until the GHG Emissions (PolGHG) is within the allowable margin (PolMargin) of the GHG emissions Limit (PolGHGLimit).

The key equations of ConstrainAvailabilityBasedOnPollution follow:

Availability factor from pollution constraint:
PolAvFactor = Minimum (PolAvFactor*(PolGHGLimit/PolGHG)**PolIncr, 1)
rerunning until either:

a. *abs*(PolGHG-PolGHGLimit) > PolMargin*PolGHGLimit
b. PolGHG-PolGHGLimit > 0 *and* PolAvFactor eq 1.00)

Table 50summarizes the variable names and definitions of the key input and output variables to the *ConstrainAvailabilityBasedOnPollution* procedure.

Table 50: Input and Output Variables - ConstrainAvailabilityBasedOnPollution

ConstrainAvailabilityBasedOnPollution Inputs and Outputs
Key inputs
PolGHG (Area,Year) = GHG Emissions from Dispatched Generation (Tonnes)
PolGHGLimit (Area,Year) = Limit on GHG Emissions (Tonnes/Yr)
PolIncr (Area,Year) = Increment Parameter for Emission Constraint (Tonnes/Tonnes)
PolMargin (Area) = Allowable Margin on Emissions (Tonnes/Tonnes)
Key outputs
PolAvFactor (Plant,Area,Year) = Availability Factor from Pollution Constraint (MW/MW)

Procedure OutputsFromDispatch

Calculates outputs resulting from dispatch, such as generation totaled across different sets, unit costs, stranded investments for retired units, imports and exports.

Equations in *OutputsFromDispatch* are listed below:

1. UnRes=∑(UnEGTM*UnResFlag)
2. UUnEGA=∑(UnEGTM)
3. UnEGA=∑(UnEGTM)
   a. unless UnEGA=XUnEGA
4. EGNDA=EGNDA+UnEGA*, accumulated across all units*

5. EGNDAuu=EGNDAuu+UUnEGA, accumulated across all units
6. UnOUEG=UnEGGross-UnEGA
    a. UnEGGross=UnEGA/(1-UnOUREG)
7. UnOUGC=UnGC-UnGCNet
    a. UnGCNet=UnGC*(1-UnOURGC)
8. EGA= ∑(EGNDA)
9. EGAuu=∑(EGNDAuu)
10. UnPCF=UnEGA/(UnGC*8760/1000)
11. UnPCFuu=UUnEGA/(UnGC*8760/1000)
12. PCF=EGA/(GCG*8760/1000)
13. FPECC=∑(UnFP*UnEGA*UnHRt)/∑(UnEGA*UnHRt)
14. FPPCost=FPECC
15. SICstG=SICstG+(UnNA*CCR+UnSLDPR) , *accumulated across all units*
16. AFC=AFCCum/GCCum
17. AVC=AVCCum/EGCum
18. ACE=(AFCCum+AVCCum)/EGCum
19. PAF=PAFCum/GCCum
    a. AFCCum=AFCCum+UnAFC**max*(UnGC,0.000001), *accumulated across all units*
    b. GCCum=GCCum+*max*(UnGC,0.000001), *accumulated across all units*
    c. AVCCum=AVCCum+UnAVC**max*(UUnEGA,0.000001), *accumulated across all units*
    d. EGCum=EGCum+*max*(UUnEGA,0.000001), *accumulated across all units*
    e. PAFCum=PAFCum+∑(UnEGC*HDHours)/ ∑(HDHours), *accumulated across all units*
20. AreaSales=∑(HDLLoad*HDHours)/1000
21. ExpSales=∑(HDLLoad*HDHours)/1000
22. AreaPurchases=∑(HDLLoad*LLEff*HDHours)/1000
23. ExpPurchases=∑ (HDLLoad*LLEff*HDHours)/1000

OutputsFromDispatch Inputs and Outputs

Key inputs

CCR $_{Plant,GenCo,Year}$ = Capital Charge Rate (1/YR)

HDHours $_{TimeP,Month}$ = Number of Hours in the Interval (Hours)

HDLLOAD $_{Node,NodeX,TimeP,Month,Year}$ = Loading on Transmission Lines (MW)

LLEff $_{Node,NodeX,Year}$ = Transmission Line Efficiency (MW/MW)

UnAFC $_{Unit,Year}$ = Average Fixed Costs ($/KW)

UnAVC $_{Unit,Year}$ = Average Variable Costs ($/MWh)

UnEGC $_{Unit,TimeP}$,Month,Year = Effective Generating Capacity (MW)

UnEGTM $_{Unit,TimeP,Month,Year}$ = Generation (GWH)

UnFP $_{Unit,Year}$ = Fuel Price ($/mmBtu)

UnGC $_{Unit,Year}$ = Gross Generating Capacity (MW)

UnGC $_{Unit,Year}$ = Gross Generating Capacity (MW)

UnHRt $_{Unit,Year}$ = Heat Rate (BTU/KWh)

UnNA $_{Unit,Year}$ = Net Asset Value of Generating Unit (M$)

UnOUREG $_{Unit,Year}$ = Own Use Rate for Generation (MW/MW)

UnOURGC $_{Unit,Year}$ = Own Use Rate for Generating Capacity (MW/MW)

UnResFlag $_{Unit,TimeP,Month,Year}$ = Flag to Indicate if Unit is Forced On to Provide Reserves (1=Yes)

UnSLDPR $_{Unit,Year}$ = Depreciation (M$/Yr)

Key outputs

ACE $_{Plant,GenCo,Year}$ = Average Cost of Energy ($/MWh)

AreaPurchases $_{Area,Year}$ = Purchases from Areas in the same Country (GWH/Yr)

AreaSales $_{Area,Year}$ = Sales to Areas in the same Country (GWH/Yr)

AVC $_{Plant,GenCo,Year}$ = Average Variable Costs ($/MWH)

EGA $_{Plant,GenCo,Year}$ = Electricity Generated (GWh/YR)

EGAuu $_{Plant,GenCo,Year}$ = Electricity Generated (GWh/YR)

EGNDA $_{Plant,Node,GenCo,Year}$ = Electricity Generation (GWh/YR)

EGNDAuu $_{Plant,Node,GenCo,Year}$ = Electricity Generation (GWh/YR)

ExpPurchases $_{Area,Year}$ = Purchases from Areas in a different Country (GWH/Yr)

ExpSales $_{Area,Year}$ = Sales to Areas in a different Country (GWH/Yr)

FPECC $_{Fuel,ECC,Area,Year}$ = Fuel Prices excluding Emission Costs ($/mmBtu)

FPPCost $_{Fuel,ECC,Area\ ,Year}$= Fuel Prices including Emission Costs ($/mmBtu)

PAF $_{Plant,GenCo,Year}$ = Plant Availability Fractor (MW/MW)

PCF $_{Plant,GenCo,Year}$ = Plant Capacity Factor (MW/MW)

SICst$_{G\ GenCo,Year}$ = Stranded Investment Cost by GenCo (M$/Yr)

UnEGA $_{Unit,Year}$ = Net Generation (GWH)

UnOUEG $_{Unit,Year}$ = Own Use Generation (GWh/Yr)

UnOUGC $_{Unit,Year}$ = Own Use Generating Capacity (MW)

UnPCF $_{Unit,Year}$ = Unit Capacity Factor (MW/MW)

UnPCFuu $_{Unit,Year}$ = Unit Capacity Factor (MW/MW)

UnRes $_{Unit,Year}$ = Generation while Unit is Forced On to Provide Reserves (GWH)

UUnEGA $_{Unit,Year}$ = Endogenous Generation (GWH)

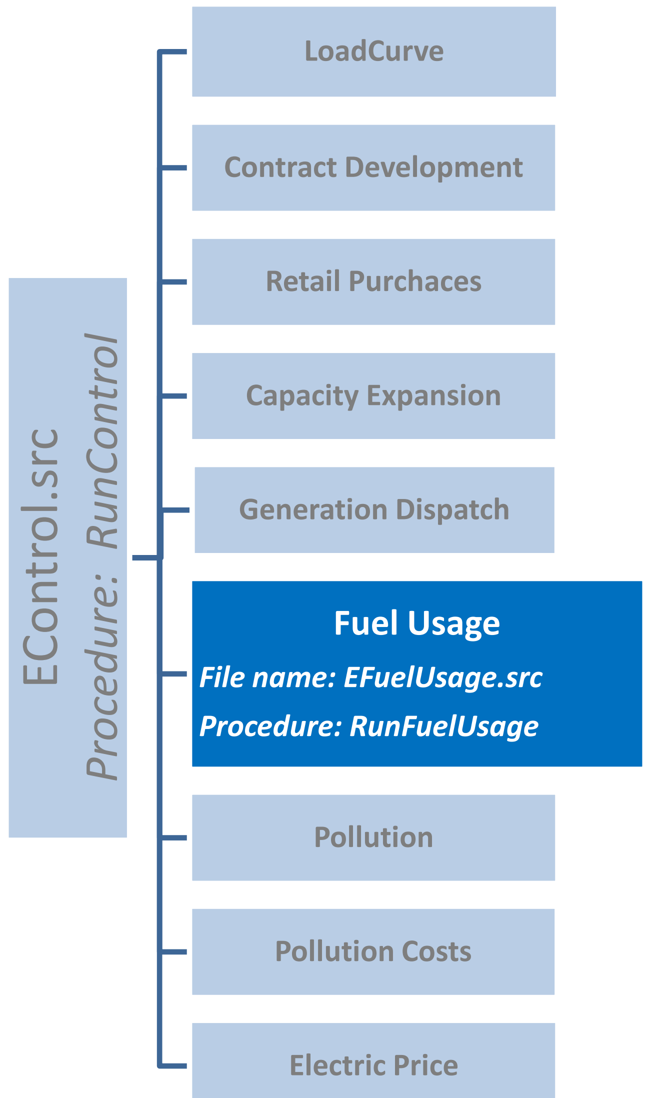
8. Fuel Usage Submodule

EFuelUsage.src contains the source code and procedures that make up the fuel usage submodule within the electric supply sector. The fuel usage submodule's main procedure is named *RunFuelUsage* and is called from the *RunControl* procedure inside EControl.src. It is the executed following generation dispatch.

Submodule Objective

The objective of the fuel usage submodule is to aggregate and summarize various results (in particular fuel consumed by electric units) from the fuel usage submodule into forms suitable for output and use in other sections of the model.

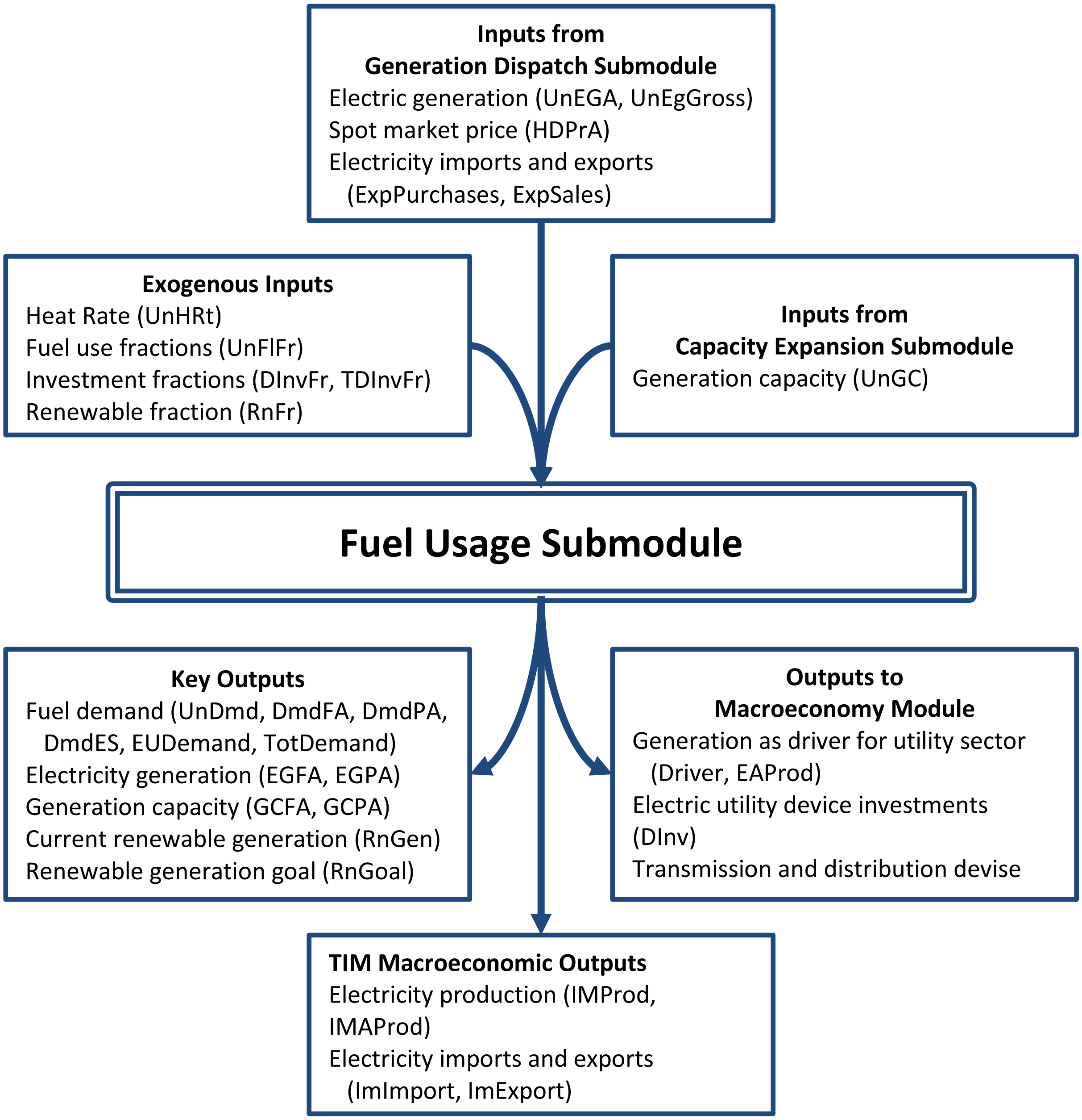
Figure 28: Fuel Usage in Electric Supply



Submodule Methodology

Creates unit fuel demands (UnDmd) and (UUnDmd) from gross generation (UnEGGross) and the heat rate (UnHRt).

Figure 29. Fuel Usage Submodule Diagram of Inputs and Outputs



Submodule Procedures

The procedures used in the demand summary are found in the *EFuelUsage.src* file and called from the *RunFuelUsage* procedure.

Figure 30 provides a diagram listing each of the procedures called in *RunFuelUsage* and illustrates the order of procedures called.

Figure 30: Procedure RunFuelUsage in EFuelUsage.src

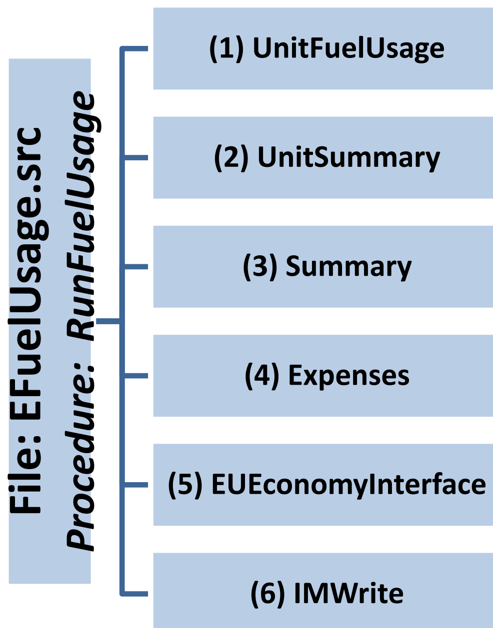


Table 51 below provides a summary of each of the procedures called within the fuel usage submodule.

Table 51: Description of Procedures within Fuel Usage

Procedure Description	Key Outputs
1. UnitFuelUsage The procedure UnitFuelUsage creates unit fuel demands (UnDmd) and (UUnDmd) from the gross generation (UnEGGross), the heat rate (UnHRt), and the fuel fraction (UnFlFr).	Unit fuel demands UnDmd and UUnDmd

2. UnitSummary Accumulates Demand, Generation, and Capacity by fuel and plant type.	DmdFA, DmdPA, EGFA, EGPA, GCFA, GCPA.
3. Summary Aggregates Renewable Generation (RnGen) and, depending on BugSw, Renewable Goal (RnGoal), and Demand (DmdFA) into demands for the utility generation sector (DmdES, EuDemand, TotDemand).	RnGen, RnGoal, DmdES, EUDemand, TotDemand
4. Expenses Calculates Device Investments, Transmission and Distribution Investments.	DInv, TDInv
5. EUEconomyInterface Exports Driver (Driver) to the rest of the Economy segments of the model.	Driver
6. IMWrite Prepares various variables for use in Canada's macroeconomic model, TIM.	IMProd, IMAProd, IMWholePrice, IMPImport, IMExport.

Procedure UnitFuelUsage

UnitFuelUsage Inputs and Outputs

Key inputs

UnEgGross $_{Unit,Year}$ = Gross Generation (GWh/Yr)

UnFlFr $_{Unit,FuelEP,Year}$ = Fuel Fraction (BTU/BTU)

UnHRt $_{Unit,Year}$ = Heat Rate (BTU/KWh)

Key outputs

UnDmd $_{Unit,FuelEP,Year}$ = Energy Demand (TBtu)

UUnDmd $_{Unit,FuelEP,Year}$ = Endogenous Energy Demand (TBtu)

The procedure UnitFuelUsage creates UnDMD and UUnDmd from the Gross Generation (UnEGGross) the heat rate (UnHRt), and the Unit Fuel Fraction (UnFlFr).

UnDmd is used in emissions related formulas in EPollution.src [and various text files]. UUnDmd is where the model-generated endogenous demand saved in the cases when unit demand is exogenously specified, and is output to serve as a potential check on the model.

Key equations in UnitFuelUsage are as follows:

KeyEquation UnitFuelUsage

<u>*Unit energy demands*</u>
UnDmd = *max*(UnEGGross*UnHRt/1e6*UnFlFr,0)

Procedure UnitSummary

This procedure accumulates unit-level Generation (UnEGA) and Capacity (UnGC) into area-level Generation (EGFA, EGPA) and Capacity (GCFA, GCPA) by fuel and plant type, respectively. Demand (DmdFA, DmdPA) is calculated from unit-level Generation (UnEGA), Heat Rate (UnHRt), and Fuel Fraction (UnFlFr).

UnitSummary Inputs and Outputs

Key inputs
$\text{UnDmd}_{\text{Unit,FuelEP,Year}}$ = Energy Demand (TBtu)
$\text{UnEGA}_{\text{Unit,Year}}$ = Generation (GWH)
$\text{UnGC}_{\text{Unit,Year}}$ = Generation Capacity (MW)
$\text{UnFlFr}_{\text{Unit,FuelEP,Year}}$ = Fuel Fraction (BTU/BTU)
$\text{UnHRt}_{\text{Unit,Year}}$ = Heat Rate (BTU/KWh)

Key outputs
$\text{DmdFA}_{\text{Fuel,Area,Year}}$ = Energy Demand (TBtu/Yr)
$\text{DmdPA}_{\text{Plant,Area,Year}}$ = Energy Demand (TBtu/Yr)
$\text{EGFA}_{\text{Fuel,Area,Year}}$ = Electricty Generation (GWh/Yr)
$\text{EGPA}_{\text{Plant,Area,Year}}$ = Electricty Generation (GWh/Yr)
$\text{GCFA}_{\text{Fuel,Area,Year}}$ = Generation Capacity (GWh/Yr)
$\text{GCPA}_{\text{Plant,Area,Year}}$ = Generation Capacity (GWh/Yr)

Fuel-type Demand (DmdFA) is used in emissions calculations in EPollution. Plant-type Generation (EGPA) is used in various calculations within the Fuel Use submodule. All six variables (DmdFA, DmdPA, EGFA, EGPA, GCFA, GCPA) are widely used as model output.

Key equations in UnitSummary are all accumulated across multiple units either by fuel or by plant type, with each unit adding a particular component to the total:

KeyEquations UnitSummary

1. DmdFA = DmdFA + UnDmd, *accumulated across fuels*
   a. DmdFA = DmdFA + UnEGA*UnHRt/1e6, *for units which do not burn emissions-producing fuels*
2. DmdPA = DmdPA + $\sum_{\text{FuelEP}}$ UnDmd, *accumulated across plant types*
   a. DmdPA = DmdPA + UnEGA*UnHRt/1e6, *for units which do not burn emissions-producing fuels*
3. EGFA = EGFA + UnEGA*UnFlFr, *accumulated across fuels*
4. EGPA = EGPA + UnEGA, *accumulated across plant types*
5. GCFA = GCFA + UnGC, *accumulated across fuels*
6. CGPA = GCPA + UnGC, *accumulated across plant types*

Procedure Summary

This procedure aggregates Plant-type Generation (EGPA) Renewable Generation (RnGen). Renewable Goal (RnGoal) is aggregated from Sales (SAEC) and the Renewable Fraction (RnFr). The procedure also aggregates Demand (DmdFA) into various demands for the utility generation sector (DmdES, EuDemand, TotDemand).

Summary Inputs and Outputs

Key inputs

DmdFA $_{Fuel,Area,Year}$ = Energy Demand (TBtu/Yr)

EGPA $_{Plant,Area,Year}$ = Electricty Generation (GWh/Yr)

RnFr $_{Area,Year}$ = Renewable Fraction (BTU/BTU)

SAEC $_{ECC,Area,Year}$ = Sales (GWh/Yr)

Key outputs

RnGen $_{Area,Year}$ = Renewable Current Level of Generation (GWh/Yr)

RnGoal $_{Area,Year}$ = Renewable Generation Goal (GWh/Yr)

DmdES $_{Fuel,Area,Year}$ = Energy Demands (TBtu/Yr)

EUDemand $_{Fuel,ECC,Area,Year}$ = Energy Demands (TBtu/Yr)

TotDemand $_{Fuel,ECC,Area,Year}$ = Energy Demands (TBtu/Yr)

Renewable Generation (RnGen) and Renewable Goal (RnGoal) are used in outputs, EPollution.src equations, and Capacity Expansion (with the caveat that RnGoal is separately calculated within ECapacityExpansion.src). The various forms of Demand (DmdES, EUDemand, TotDemand) are used in the Supply Sector and as model output.

Key equations in Summary are as follows:

KeyEquations Summary

1. RnGen = $\sum_{Plant}$ EGPA
2. RnGoal = ($\sum_{ECC}$ SaEC)*RnFrArea
3. DmdES = DmdFA
4. EuDemand = DmdFA
5. TotDemand = DmdFA

Procedure Expenses

This procedure calculates Device investments (DInv) and Electric Transmission and Distribution Investments (TDInv) from the Generation Capacity (GCPA) and their respective Investment Fractions (DInvFr, TDInvFr), which are model inputs.

These investments (DInv, TDInv) are aggregated with other industries in the Supply

Expenses Inputs and Outputs

Key inputs

GCPA $_{Plant,Area,Year}$ = Generation Capacity (MW)

DInvFr $_{Plant,Area,Year}$ = Device Investments Fraction ($/KW/Yr)

TDInvFr $_{Plant,Area,Year}$ = Electric Transmission and Distribution Investments Fraction ($/KW/Yr)

Key outputs

TInv $_{ECC,Area,Year}$ = Device Investments (M$/Yr)

TDInv $_{Area,Year}$ = Electric Transmission and Distribution Investments (M$/Yr) sector for input to the Informetrica Model.

Key equations in Expenses are as follows:

KeyEquations Expenses

1. $DInv = \sum_{Plant} (GCPA*DInvFr)*Infla*1000/1000000$
2. $TDInv = \sum_{Plant} (GCPA*TDInvFr)*Infla*1000/1000000$

Procedure EUEconomyInterface

EUEconomyInterface Inputs and Outputs
Key inputs
EGPA $_{Plant,Area,Year}$ = Electricity Generation (GWh/Yr)
Key outputs
Driver $_{ECC,Area,Year}$ = Economic Driver (Various Millions/Yr)
EAProd $_{Plant,Area,Year}$ = Electric Utility Production (GWh/Yr)

This procedure calculates two variables from the plant-type Generation (EGPA). First is the Economic Driver (Driver) for the Utility Generation Economic Category and is used in the Macroeconomic sector of the model. The second is the Electric Utility Production (EAProd) which is used in IMWrite for use in the Informetrica model.

Key equations in EUEconomyInterface are as follows:

KeyEquations EuEconomy Interface

1. $Driver = \sum_{Plant} EGPA$
2. $EAProd = EGPA$

Procedure IMWrite

This procedure prepares various variables for use in the Informetrica model. Production (IMProd, IMAProd) is calculated from Electric Utility Production (EAProd). The Electricity Wholesale Price is a four-year smooth of the Average Nodal Price (HDPrAve) weighted by Energy requirements (HDEnergy). Electricity Imports and Exports (IMImport, IMExport) are calculated from the Sales to and Purchases from Areas in different Countries (ExpSales, ExpPurchases).

IMWrite Inputs and Outputs

Key inputs

$EAProd_{Plant,Area,Year}$ = Electric Utility Production (GWh/Yr)

$ExpPurchases_{Area,Year}$ = Purchases from Areas in a different Country (GWh/Yr)

$ExpSales_{Area,Year}$ = Sales to Areas in a different Country (GWh/Yr)

$HDEnergy_{Node,TimeP,Month,Year}$ = Energy In Interval (GWH)

$HDPrA_{Node,TimeP,Month,Year}$ = Spot Market Price ($/MWh)

Key outputs

$IMAProd_{Fuel,CNArea,Year}$ = Provincial Energy Production (PJ/Yr)

$IMProd_{Fuel,Year}$ = Energy Production (PJ/Yr)

$IMWholePrice_{Fuel,Year}$ = Wholesale Energy Price (2000 $CN/GJ)

$IMExport_{Fuel,Year}$ = Energy Exports (PJ/Yr)

$IMImport_{Fuel,Year}$ = Energy Imports (PJ/Yr)

These variables are only used as inputs to the Informetrica Model.

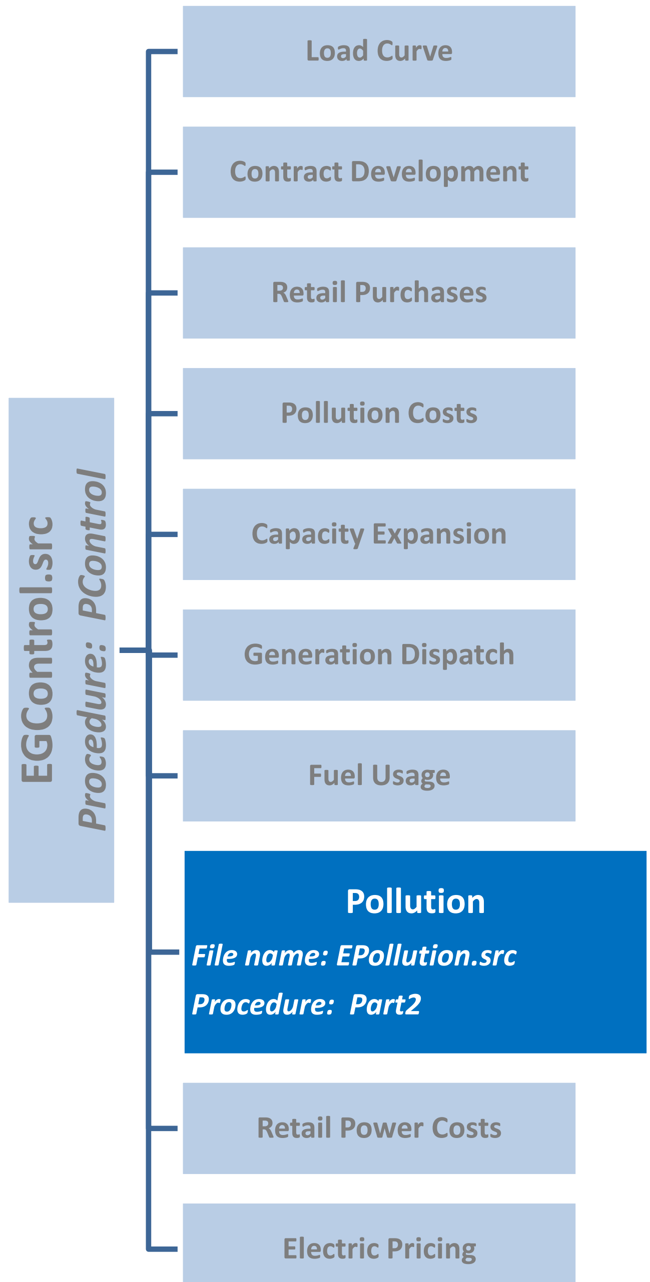
Key equations in IMWrite are as follows:

KeyEquations
IMWrite

1. IMAProd = ($\sum_{Process}$ EAProd)*EEConv/1e6*KJBtu
2. IMProd(F) = $\sum_{CNArea}$ (IMAProd)
3. IMWholePrice = ∑(HDPrA*HDEnergy/1000) / ∑(HDEnergy*EEConv/1e6*KJBtu)/ Infla*Infla*Exchg
    a. note: IMWholePrice is smoothed over four years
4. IMExport = (∑ExpSales)*EEConv/1e6*KJBtu
5. IMImport = (∑ExpPurchases)*EEConv/1e6*KJBtu

9. Pollution Submodule

Figure 31. Pollution in Electric Supply



EPollution.src contains the source code and procedures that make up the pollution submodule. The pollution submodule's main procedure is named *Part2* and is called from the *PControl* procedure inside EGControl.src. It is called after directly after the Fuel Usage Submodule has been executed.

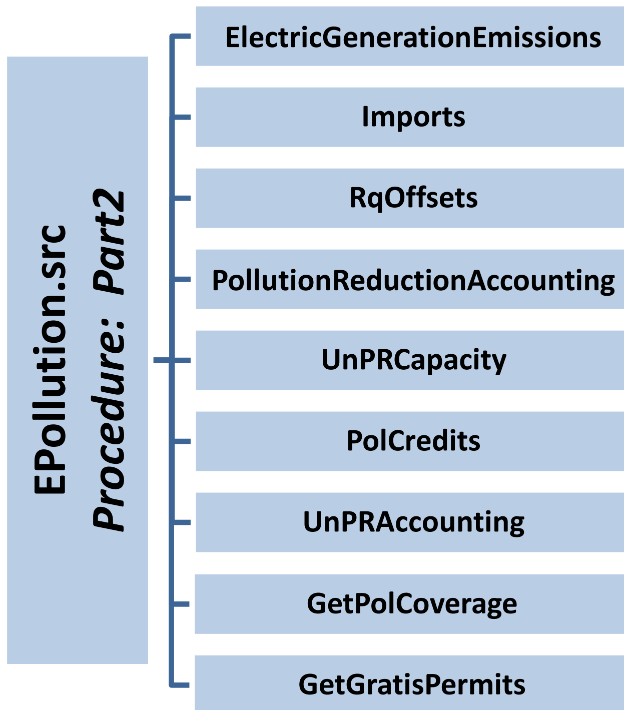
Submodule Objective

The objective of the pollution submodule is twofold. First, the submodule calculates the emissions from electricity generation on the unit level. Second, the submodule applies various pollution related policies. These include but are not limited to offsets, emissions-related capital retirements and construction, Alberta CASA policies, and the assignment of gratis permits.

Submodule Procedures

The main procedures called from the *Part2* procedure in EPollution.src are shown in Figure 32Figure 32 below.

Figure 32. Procedure Part2 in EPollution.src



The following Table 52 provides a summary of each of the procedures within the Pollution Submodule (Part 2). It also lists the key outputs from each of those procedures.

Table 52. Description of Procedures within Pollution

Procedure Description	Key Outputs
1. ElectricGenerationEmissions Energy usage and generation are multiplied with emissions coefficients to produce emission inventories	Utility emissions (UnPol, MEPol)
2. Imports Calculation of emission inventories for imported electricity	PolImports
3. RqOffsets Set the number of offsets required for unit if necessary	OffRq
4. PollutionReductionAccounting Simulates the initiation, construction, and retirement of capital to reduce emissions at the sector level	Spending on reduction capital (PRExp)

5. **UnPRCapacity** Set capacity for emission reductions at the unit level using emission targets	Unit reduction capacity (UnRCR)
6. **PolCredits** Simulates emission credit system for Alberta CASA policies	Unit reduction costs and capacity (UnRCC2, UnRCR2)
7. **UnPrAccounting** Simulates the initiation, construction, and retirement of capital to reduce emissions at the unit level	Spending on reduction capital (PRExp)
8. **GetPolCoverage** Calculate amount of emissions covered under regulatory policies	Covered pollution (PolCov)
9. **GetGratisPermits** Determine the number of gratis permits available to be deducted from the covered emissions	Gratis permits (PGratis)

Procedure ElectricGenerationEmissions

ElectricGenerationEmissions Inputs and Outputs
Key Inputs
UnDmd $_{Unit,FuelEP,Year}$ = Energy Demands (TBtu)
UnEGA $_{Unit,Year}$ = Generation (GWH)
UnPOCA $_{Unit,FuelEP,Poll,Year}$ = Average Pollution Coefficient (Tonnes/TBtu)
UnSqFr $_{Unit,Poll,Year}$ = Sequestered Pollution Fraction (Tonne/Tonne)
Key outputs
CgPolUnit $_{Fuel,ECC,Poll,Area,Year}$ = Pollution from Industrial Units (Tonnes/Yr)
GrossPol $_{ECC,Poll,Area,Year}$ = Gross Pollution - before any policies (Tonnes/Yr)
MEPol $_{ECC,Poll,Area,Year}$ = Process Pollution (Tonnes/Year)
UnMEPol $_{Unit,Poll,Year}$ = Process Pollution (Tonnes)
UnPol $_{Unit.FuelEP.Poll.Year}$ = Pollution (Tonnes)

This procedure utilizes demand, generation, and emissions coefficients to create the inventory of energy-based and process emissions produced from electric generation. Emission inventories are the total amount of emissions produced for a given unit per year. These values are calculated in the model by multiplying the amount of energy consumed by the marginal rate of emissions produced from consuming energy for each electric unit. For sector level and cogeneration inventories, the inventories produced by each unit are agglomerated and saved into a final total value.

Key equations in *ElectricGenerationEmissions* are as follows:

KeyEquations
ElectricGeneration Emissions

1. UnPol= UnDmd*UnPOCA (1-UnSqFr)
2. UnMEPol = *max*(UnEGA*UnMECX,0)
3. MEPol = ∑ UnMEPol
4. CgPolUnit = CgPolUnit + UnPol, *accumulated across Units*
5. GrossPol = ∑ (EUPol/EURM) * ECoverage + MEPol * ECoverage

Procedure Imports

Imports Inputs and Outputs
Key Inputs
UnEGA $_{Unit,Year}$ = Generation (GWH)
UnFrImports $_{Unit,Area,Year}$ = Fraction of Unit Imported to Area (GWH/GWH)
Key outputs
PolImports $_{Poll,Area,Year}$ = Emissions from Imported Electricity (Tonnes)

Emission inventories for electricity purchased from a different area are calculated for use in the total emissions inventory. Some emissions policies also account for "imported emissions" due to higher emission electric generation from an area outside the area covered by the policy.

The Key equation in *Imports* follows:

KeyEquations
Imports

1. PolImports = PolSpImport+PolOthImports+PolRnImports, *where*
   a. PolSpImport = ∑(UnPol*UnFrImports)
   b. PolOthImports = ∑ (GrImports*POCXOthImports) +XPolOthImports, *where in sequence*
      i. GrImports=∑(HDLLoad*HDHours*NdArFr)/1000
      ii. GrImpTot=∑(GrImports)
      iii. GrImpAdj=xmax(GrImpTot-EGSpImports-RnImports,0)/GrImpTot
      iv. GrImports=GrImports*GrImpAdj*GrImpMult
   c. PolRnImports=RnImports*POCXRnImports
      i. RnImports=xmax(RnGoal-RnGen,0)

Procedure RqOffsets

If a unit is instructed to offset its emissions (**OffSw**) then the amount of offsets required is set based on the unit's emissions.

The key equation in RqOffsets is as follows:

KeyEquations *RqOffsets*

OffRq = ∑(UnPol*PolConv)

RqOffsets Inputs and Outputs
Key Inputs
OffSw $_{Area,Year}$ = GHG Electric Utility Offsets Required Switch (1=Required)
PolConv $_{Poll}$ = Pollution Conversion Factor (convert GHGs to eCO2)
UnPol $_{Unit,FuelEP,Poll,Year}$ = Pollution (Tonnes)
Key outputs
OffRq $_{Area,Year}$ = GHG Electric Utility Offsets Required (Tonnes/Yr)

Procedure PollutionReductionAccounting

The total amount spend on emission reduction in the electric generation sector is calculated based on the marginal cost of reduction capital and the amount of capital needed per year. Altering the marginal emissions coefficient in ENERGY 2020 is simulated by developing reduction capital, which would include reduction devices such as smokestack scrubbers. For each given year this procedure brings online reduction capital that has finished construction, retires old capital that has reached the end of its lifespan, and initiates new construction if necessary to meet the reduction amount required. The total amount spend on construction by the private sector is saved after accounting for any government subsidies.

PollutionReductionAccounting Inputs and Outputs
Key Inputs
AGFr $_{ECC,Poll,Area,Year}$ = Government Subsidy ($/$)
EURCAP $_{FuelEP,Plant,Poll,Area,Year}$ = Reduction Capacity (Tonnes/Year)
EURCCEm $_{FuelEP,Plant,Poll,Area,Year}$ = Embedded Reduction Capital Cost ($/Tonnes)
EURCD $_{Poll}$ = Reduction Capital Construction Delay (Years)
EURCPL $_{Poll}$ = Reduction Capital Physical Life (Years)
EURCR $_{FuelEP,Plant,Poll,Area,Year}$ = Reduction Capital Completion Rate (Tonnes/Year/Year)
EURM $_{FuelEP,Plant,Poll,Area,Year}$ = Reduction Multiplier by Area (Tonnes/Tonnes)
EUROCF $_{FuelEP,Plant,Poll,Area,Year}$ = Polution Reducution O&M Cost Factor ($/$)
EURP $_{FuelEP,Plant,Poll,Area,Year}$ = Pollutant Reduction (Tonnes/Tonnes)
PAdCost $_{ECC,Poll,Area,Year}$ = Policy Administrative Cost ($/Year)
Key outputs
GRExp $_{ECC,Poll,Area,Year}$ = Reduction Government Expenses ($/Year)
PRExp $_{ECC,Poll,Area,Year}$ = Reduction Private Expenses (M$/Yr)

Key equations in *PollutionReductionAccounting* are as follows:

KeyEquations
PollutionReduction Accounting

1. GRExp =∑(EURCR*EURCC*AGFr)/1e6+PAdCost
2. PRExp = ∑ (EURCR*EURCC*(1-AGFr)+EURCCEm*EUROCF)/1e6

Procedure UnPRCapacity

UnPRCapacity Inputs and Outputs
Key Inputs
EURCD $_{Poll}$ = Reduction Capital Construction Delay (Years)
EURCPL $_{Poll}$ = Reduction Capital Physical Life (Years)
UnPol $_{Unit,FuelEP,Poll,Year}$ = Pollution (Tonnes)
UnRM $_{Unit,FuelEP,Poll,Year}$ = Pollution Reduction Multiplier (Tonnes/Tonnes)
UnRP $_{Unit,FuelEP,Poll,Year}$ = Pollution Reduction Requirement (Tonnes/Tonnes)
Key outputs
UnRCR $_{Unit,FuelEP,Poll,Year}$ = Pollution Reduction Completion Rate (Tonnes/Yr/Yr)

The procedure begins by calculating and vintaging the capacity of requipment used in reducing emissions. This procedure produces the amount of emissions needed to be reduced by each unit and construction of reduction capital required to meet the goal. The Indicated Reduction Capcity (UnRICap) is constructed by removing the effects of pollution reduction for the unit (UnRM) from its actual pollution (UnPol), but reapplying the required reduction (UnRP) to find out how many tonnes of pollution could be reduced. This is combined with the Pollution Reduction Capacity (UnRCap) and Pollution Reduction Completion Rate (UnRCR) from the previous year to create the Capacity Initiation Rate (UnRCI). The Reduction Capcity and Reduction Completion (UnRCap, UnRCR) rate are then updated and lagged based on the above variables.

The key equations in UnPrCapacity are mostly grounded in updating variables from the previous year.

KeyEquations
PollutionReduction Accounting

1. UnRICap=UnPol/UnRM*UnRP
2. UnRCI = xmax(0,UnRICap-UnRCap-UnRCR*EURCD+UnRCap/EURCPL)/EURCD
3. UnRCap=UnRCap+DT*(UnRCR-UnRCap/EURCPL)
4. UnRCR=UnRCR+DT*(UnRCI-UnRCR)/EURCD

Procedure PolCredits

The procedure *PolCredits* was designed to specifically simulate Alberta CASA regulations. This code only applies to units in Alberta if they are covered by the policy as set by the policy file during the model run. For each covered unit, emission credits are purchased starting with the largest units first. If credits are unavailable, then the unit either retires or constructs reduction capital.

PolCredits Inputs and Outputs

Key Inputs

$UnPol_{Unit,FuelEP,Poll,Year}$ = Pollution (Tonnes)

$PoCredits_{Unit,Poll,Year}$ = Pollution Credits Accumulated (Tonnes)

Key outputs

$PoCreditsNeeded_{Unit,Poll,Year}$ = Pollution Credits Needed (Tonne/Yr)

$UnPRCost_{Unit,Year}$ = Levelized Cost of Unit with Pollution Reduction Equipment ($/MWh)

$UnRCC2_{Unit,Poll,Year}$ = Pollution Reduction Capital Cost ($/Tonne)

$UnRCR2_{Unit, Poll,Year}$ = Pollution Reduction Completion Rate (Tonnes/Yr/Yr)

Procedure UnPRAccounting

This procedure controls the vintaging process for emissions reduction equipment at the unit level. It initiates, completes, and retires emission reduction capital and the amount invested each year is added to the total private and government pollution reduction expenditures.

Key equations in UnPrAccounting are as follows. Some are adjustments to previous variables.

UnPRAccounting Inputs and Outputs

Key Inputs

$UnRCC_{Unit,FuelEP,Poll,Year}$ = Pollution Reduction Capital Cost ($/Tonne)

$UnRCC2_{Unit,Poll,Year}$ = Pollution Reduction Capital Cost ($/Tonne)

$UnRCCEm_{Unit,FuelEP,Poll,Year}$ = Embedded Pollution Reduction Capital Cost ($/Tonne)

$UnROCF_{Unit,Poll,Year}$ = Pollution Reduction O&M Cost Factor ($/$)

$UnRCR_{Unit,FuelEP,Poll,Year}$ = Pollution Reduction Completion Rate (Tonnes/Yr/Yr)

$PoCredits_{Unit,Poll,Year}$ = Pollution Credits Accumulated (Tonnes)

Key outputs

$GRExp_{ECC,Poll,Area,Year}$ = Reduction Government Expenses ($/Year)

$PRExp_{ECC,Poll,Area,Year}$ = Reduction Private Expenses (M$/Yr)

$UnRCGA_{Unit,Year}$ = Emission Reduction Capital Costs (M$)

$UnRCOM_{Unit,Year}$ = Emission Reduction O&M Costs (M$)

KeyEquations
PollutionReduction Accounting

1. GRExp = GRExp + (∑(UnRCR*UnRCC) + UnRCR2*UnRCC2)*AGFr/1e6 + PAdCost
2. PRExp = PRExp + [(∑ (UnRCR*UnRCC)+UnRCR2*UnRCC2)*(1-AGFr) +UnRCCEm*UnROCF]/1e6

3. $UnRCGA = \sum_{Poll} ((\sum_{Fuel}(UnRCR*UnRCC)+ UnRCR2*UnRCC2)*(1-AGFr))/1e6$
4. $UnRCOM = \sum(UnRCCEm*UnROCF)/1e6$

Procedure GetPolCoverage

Some emissions policies only apply to part of an industry, or not every facility within an industry. As such we may only be interested in the pollution from those facilities which are covered by the policy. This procedure simulates this by calculating the amount of emissions covered by regulation as the total quantity of emissions produced in the area covered by a policy, plus the emissions from electricity imports into that area. This value is saved as an export of the electric sector for use in the broader pollution sector of the model.

GetPolCoverage Inputs and Outputs
Key Inputs
$PolConv_{Poll}$ = Pollution Conversion Factor (convert GHGs to eCO2)
$PolImports_{Poll,Area,Year}$ = Emissions from Imported Electricity (Tonnes)
$UnCoverage_{Unit,Poll,Year}$ = Fraction of Unit Covered in Emission Market (1=100% Covered)
$UnPol_{Unit,FuelEP,Poll,Year}$ = Pollution (Tonnes)
Key outputs
$PolCov_{ECC,Poll,PCov,Area,Year}$ = Covered Pollution (Tonnes/Yr)

The key equation for GetPolCoverage is as follows; it is accumulated across units within covered areas.

1. $PolCov = PolCov + \sum_{Fuel} (UnPol) * PolConv + PolImports * PolConv * ECoverage$, *accumulated across units in covered areas and active markets*

Procedure GetGratisPermits

The number of gratis permits is set depending on the type of gratis program. For units covered by an intensity target (FacSw), the value of the permits is accounted for. Otherwise, gratis permits for covered units are either calculated or set to an

GetGratisPermits Inputs and Outputs
Key Inputs
$ETAvPr_{Market,Year}$ = Average Cost of Emission Trading Allowances ($/Tonnes)
$FacSw_{Market}$ = Facility Level Intensity Target Switch (1=Facility Target)'
Key outputs
$PGratis_{ECC,Poll,PCov,Area,Year}$ = Gratis Permits (Tonnes/Year)
$UnPGratis_{Unit,Poll,Year}$ = Gratis Permits (Tonnes/Yr)
$UnPGValue_{Unit,Poll,Year}$ = Gratis Permit Value ($M/Yr)

exogenous value.

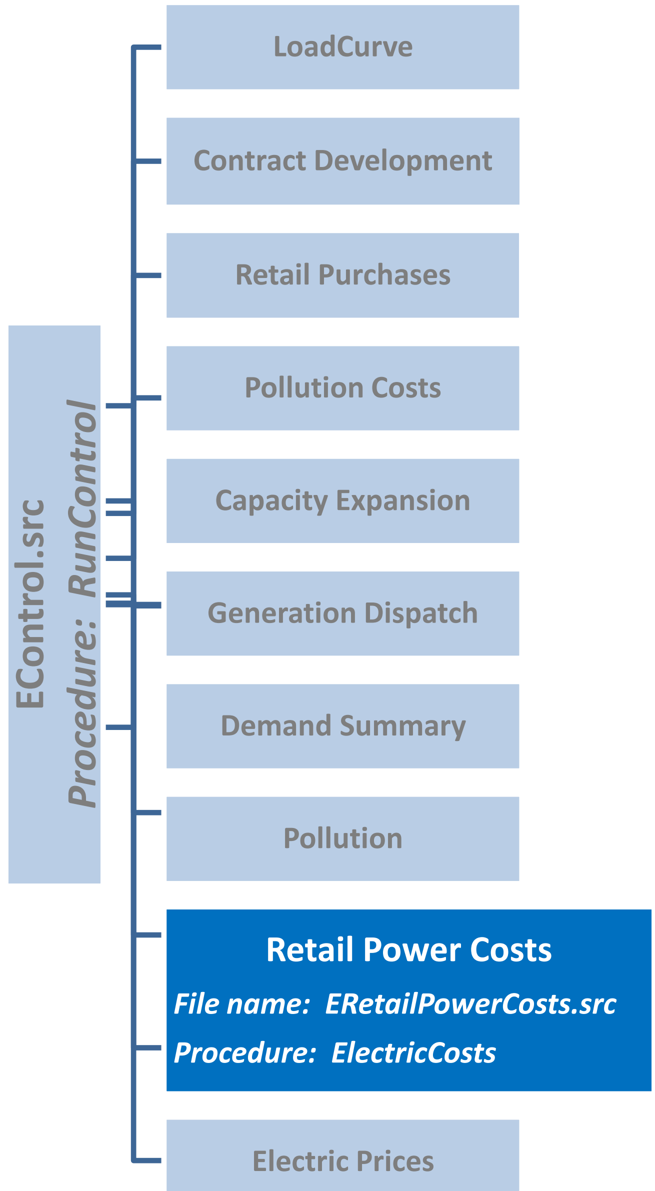
The unit gratis permits (UnPGratis) are given their values by applicable policies, and many of the relevant calculations are done partly outside the model within the associated txp files. This allows for greater speed and more flexible modeling, where multiple different policies can be included or excluded at the modeler's discression.

The key equations for GetGratisPermits follow below:

1. UnPGValue=UnPGratis*PolConv*ETAvPr/1e6
2. PGratis = PGratEx + PGratNew
    a. PGratEx = PGratEx + UnPGratis, *accumulated across online units*
    b. PGratNew = PGratNew + UnPGratis, *accumulated across units not yet online*

10. Retail Power Costs Submodule

Figure 33. Retail Power Costs in Electric Supply



ERetailPowerCosts.src contains the source code and procedures that make up the Retail Power Costs Submodule. Its main procedure is named *ElectricCosts* and is called from the *RunControl* procedure inside *EControl.src*. At the point when the Retail Power Costs Submodule gets called, the load curves have been created and retail contracts with generating companies have been developed and purchased.

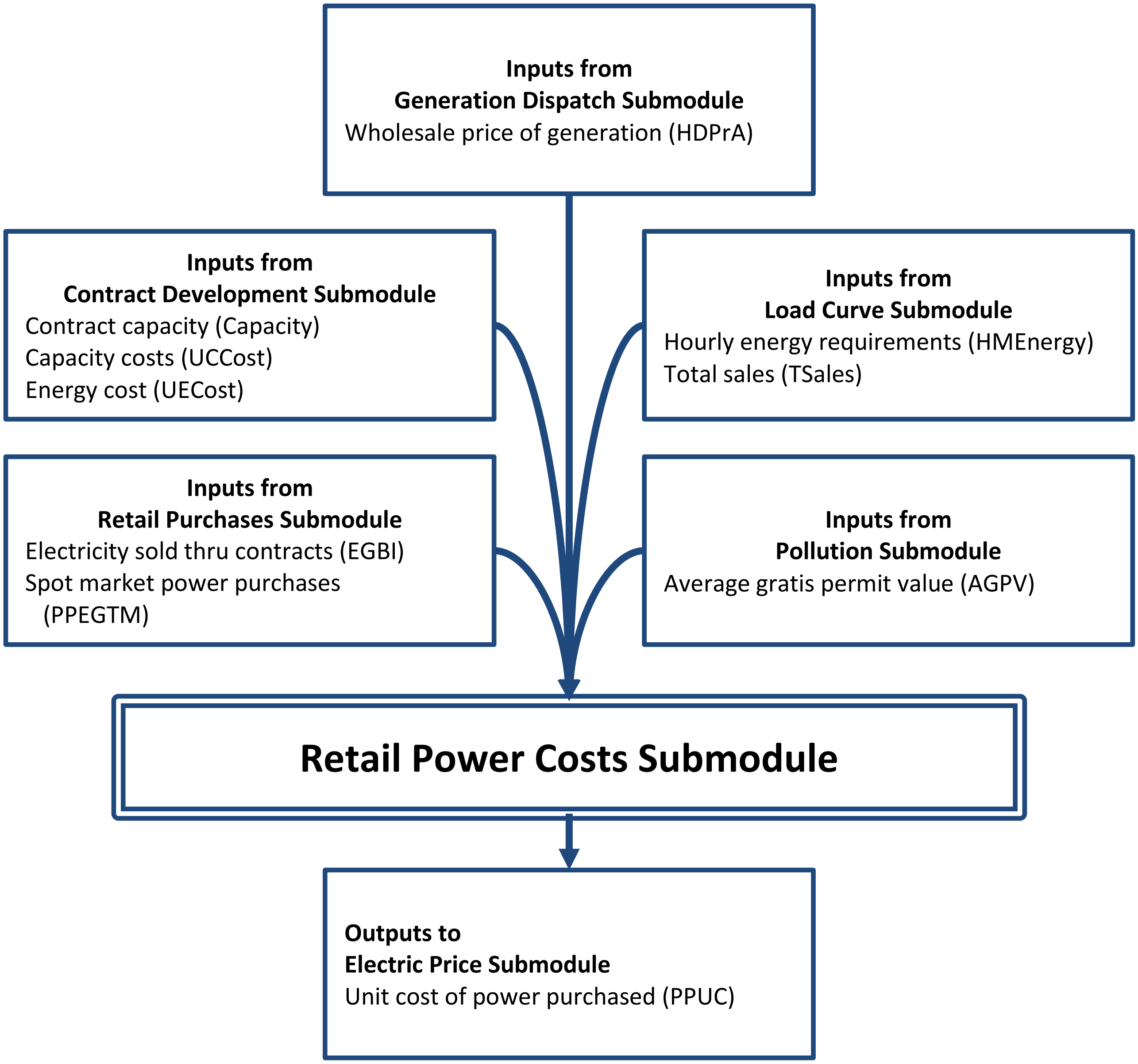
Submodule Objective

The purpose of the Retail Power Costs Submodule is to use the contract and wholesale market parameters and sales to determine both the total spent by each retail company on power purchases and the cost per unit of purchased power. The latter value is generated as a key input for calculating the final retail electric price.

Submodule Methodology

With costs (UVCost, UCCost, PPVCost) and the amount of power purchased from contracts (EGBI) and the spot market (PPEGTM) determined, ERetailPowerCosts calculates the final cost of purchasing power (PPUC) from the generating company for each retail company.

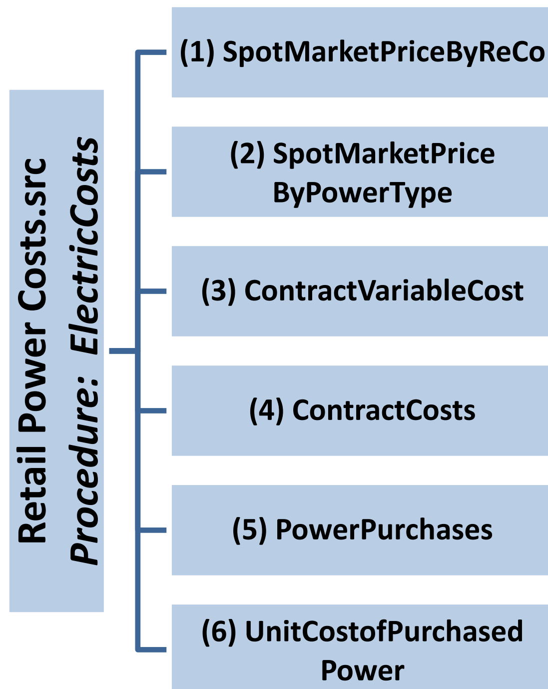
Figure 34. Retail Power Costs Submodule Diagram of Inputs and Outputs



Submodule Procedures

Below, Figure 35 lists the procedures that make up the Retail Power Purchases Submodule (*ElectricCosts* procedure).

Figure 35. Procedure ElectricCosts in ERetailPowerCosts.src



Each of these procedures is summarized in Table 53 below and the key outputs from each are listed as well. A more detailed description of the procedures is contained in the sections that follow.

Table 53. Description of Procedures within Retail Power Costs

Procedure Description	Key Outputs
1. SpotMarketPriceByReCo The retail price of spot market power is a function of the node price weighted by the retail demands at each node	Spot market price per retail company (HMPr, HMPrA)
2. SpotMarketPriceByPowerType The spot market price is saved to the appropriate power type (PPSet = 1) for later use in the model	Price by power type (PPVCost)

Procedure Description	Key Outputs
3. ContractVariableCosts Energy costs are revised by removing gratis permits if applicable	Energy costs (UVCost)
4. ContractCosts Calculate the total variable and contract costs for each retail company	Contract variable and fixed costs (DVCost, DCCost)
5. PowerPurchases Calculate the total purchases from the spot market from the spot market price and total amount purchased	Total retail spending on power purchases (PUCT)
6. UnitCostOfPurchasedPower The unit cost of purchased power is total amount spent divided by total sales	Spending per unit of power purchased (PPUC)

Procedure SpotMarketPriceByReCo

The calculated price of purchased power for each node from the electric generation dispatch is used to set the price for each retail company to purchasing off the wholesale market, weighted by the percentage of power purchased from each node by the retail company.

SpotMarketPriceByReCo Inputs and Outputs
Key Inputs $HDPrA_{Node,TimeP,Month,Year}$ = Spot Market Marginal Price $HMEnergy_{Node,ReCo,TimeP,Month}$ = Energy in Interval (GWH) Key outputs $HMPr_{ReCo,TimeP,Month,Year}$ = Spot Market Price ($/MWh) $HMPrA_{ReCo,Year}$ ='Average Spot Market Price ($/MWh)

Key Equations SpotMarketPrice ByReCo

Spot market price:

$HMPr=\sum(HDPrA*HMEnergy)/ \sum (HMEnergy)$

Procedure SpotMarketPriceByPowerType

The spot market price is saved to the appropriate power type (PPSet = 1) for later use in the model.

Key Equations SpotMarketPrice ByPowerType

Estimated spot market price:

PPVCOST=∑(PPEGTM*HMPR)/∑(PPEGTM)

SpotMarketPriceByPowerType Inputs and Outputs
Key Inputs
HMPr $_{ReCo,TimeP,Month,Year}$ = Spot Market Price ($/MWh)
PPEGTM $_{ReCo,TimeP,Month,Year}$ = 'Power Purchases (GWH)
Key outputs
PPVCOST $_{PPSet,Month,ReCo,Year}$ = Estimated Spot Market Price ($/MWh)

Procedure ContractVariableCost

ContractVariableCost Inputs and Outputs
Key Inputs
UECost $_{ReCo,GenCo,Plant,Year}$ = Contract Energy Cost (MILLS/kWh)
AGPVSw $_{GenCo}$ = Is Value of Gratis Permit passed on to Customers (1=yes)
AGPV $_{Plant,GenCo}$ = Average Gratis Permit Value ($/Yr)
Key outputs
UVCost $_{ReCo,GenCo,Plant,Year}$ = Contract Variable Cost ($/mWh)

The variable cost of the contract is calculated by removing the impact of any gratis permits on the contract energy costs. Gratis permits are regulatory permits that are freely given to the generating company instead of being purchased. The cost of all permits is incorporated in the energy cost variable, so if the permits are determined to be gratis then the impact of the permit purchase cost is removed from the variable cost of the contract. The switch to pass costs is set to 1 by default, meaning that gratis permits are refunded unless specified otherwise by the user.

Key Equations PassGratisTo Customers

Contract variable cost:

UVCost=UECost-AGPV

Procedure ContractCosts

Total contract costs are determined for each retail company by multiplying the amount of capacity or contract sales by the relevant cost per unit. The total variable cost for each retail company is the sum of the variable cost of each contract (UVCost) times the amount of contract power purchased (EGBI).

ContractCosts Inputs and Outputs
Key Inputs
Capacity $_{ReCo,GenCo,Plant,TimeP,Month,Year}$ = Capacity under Contract (MW)
EGBI $_{ReCo,GenCo,Plant,Year}$ = Electricity sold thru Contracts (GWh/Yr)
UVCost $_{ReCo,GenCo,Plant,Year}$ = Contract Variable Cost ($/MWh)
UCCost $_{ReCo,GenCo,Plant,Year}$ = Contract Capacity Cost ($/KW)
Key outputs
DVCost $_{ReCo,Year}$ = Variable Cost (M$/Yr)
DCCost $_{ReCo,Year}$ = Capacity Cost (M$/Yr)

The total contract fixed costs (UCCost) is the sum of contact capacity (Capacity) times the contract capacity costs (UCCost).

The amount of purchased power from contracts (EGBI) is an input from the retail purchases submodule. The fixed cost of contracts (UCCost) is an input from the contract development submodule.

Key Equation: ContractCosts

Contract variable/energy cost:

DVCost = ∑(EGBI*UVCost)/1000

Contract fixed/capacity cost:

DCCOST = ∑ (*max*(Capacity)*UCCost)/1000

Procedure PowerPurchases

The total cost of purchases from the spot market (**PPCT**) is the sum of the energy purchased from the spot market (**PPEGTM**) times the cost of spot market power (**PPVCost**).

PowerPurchases Inputs and Outputs
Key Inputs
PPEGTM $_{ReCo,TimeP,Month}$ = Power Purchases (GWH)
PPVCOST $_{PPSet,Month,ReCo}$ = Estimated Spot Market Price ($/MWh)
DVCOST $_{ReCo}$ = Variable Cost (M$/YR)
DCCOST $_{ReCo}$ = Capacity Cost (M$/YR)
Key outputs
PPCT $_{PPSet,ReCo}$ = Cost of Purchase Power (M$/YR)
PUCT $_{ReCo}$ = Cost of Purchase Power (M$/YR)

With both the total cost spend on contracts and the wholesale market determined, the model can now calculate the final cost of purchasing power for each retail company. Total cost of purchasing power (**PUCT**) is the sum of contract costs (**DVCost, DCCost**) plus the spot market purchases (**PPCT**).

The purchased power set is defined by: BasePP, BaseSpot, IntPP, IntSpot, PeakPP, PeakSpot, EmgPP

Key Equation: PowerPurchases

Cost of purchase power by purchased power set and retail company:
PPCT=∑(PPEGTM*PPVCOST)/1000

Cost of purchase power by retail company:
PUCT=PUCTBI+PUCTSM
Where PUCTBI=DVCOST+DCCOST

Procedure UnitCostofPurchasedPower

The cost of electricity per unit sold (**PPUC**) is the total amount spend on purchases (**PUCT**) divided by the amount of electricity sold (**TSales**)

UnitCostofPurchasedPower Inputs and Outputs
Key Inputs PUCT $_{ReCo}$ = Cost of Purchase Power (M$/YR) TSales $_{ReCo}$ = Electricity Sales (GWh/YR) Key outputs PPUC$_{ReCo}$ = 'Unit Cost of Purchase Power ($/MWH)'

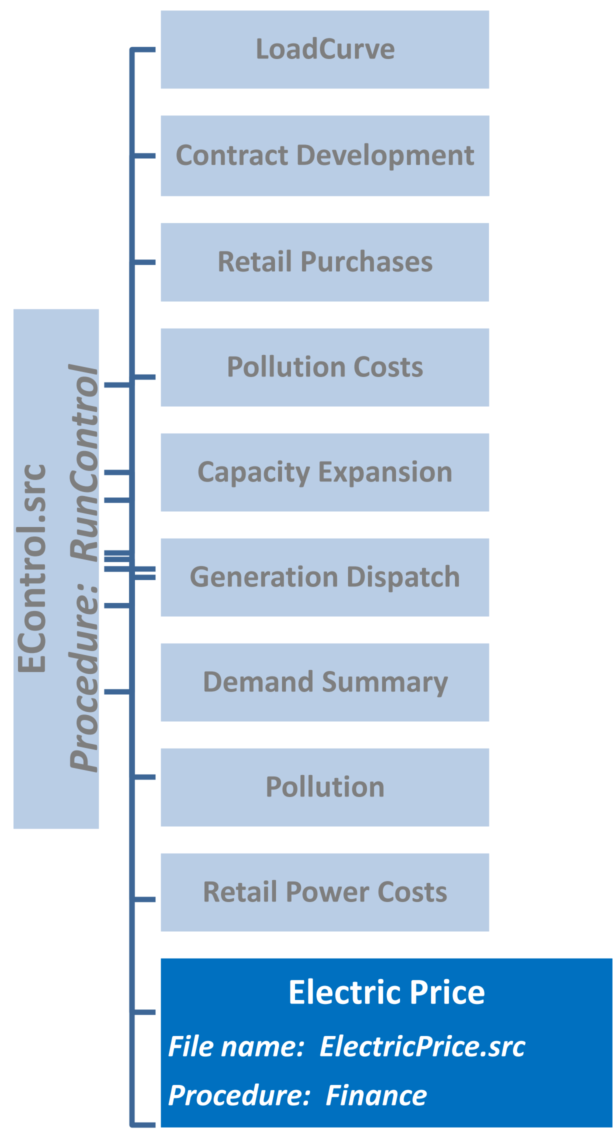
Key Equation: UnitCostof PurchasedPower

Unit cost of purchased power:
PPUC=PUCT/TSales*1000

11. Electric Price Submodule

The *ElectricPrice.src* file contains the source code and procedures that make up the electric price submodule. Its main procedure is named *Finance* and it is called from the *RunControl* procedure inside *EControl.src*. This electric price procedure is the last procedure that gets called in the electric supply module.

Figure 36: Electric Price in Electric Supply



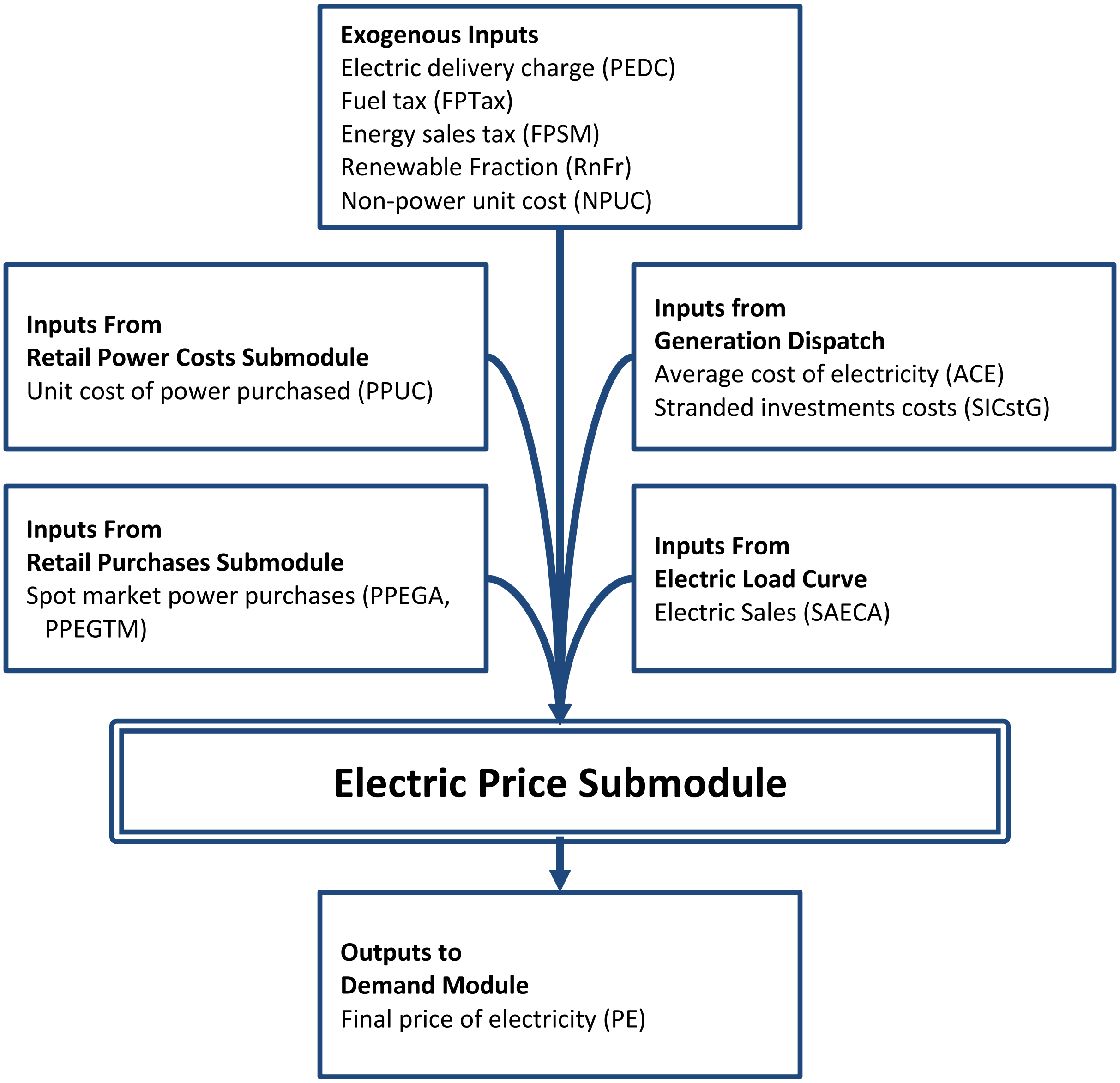
Submodule Objective

The purpose of the electric price submodule is to calculate the final price of electricity (PECalc, PE) for each retail company based on the unit cost (PPUC), delivery charge (PEDC) and other adjustments.

The generation dispatch submodule of ENERGY 2020 determines the price of producing a unit of electricity. This differs from the final price that is passed to the customer purchasing power since it doesn't include the cost of electric transmission, fuel taxes, and a number of other factors that influence the final retail price. Simulating the final retail price is key as an input for the decision making process of consumers in the demand sector.

Figure 38 illustrates the key inputs and outputs of the electric price submodule.

Figure 37. Electric Price Submodule Diagram of Inputs and Outputs



Submodule Procedures

The procedures that make up the electric price submodule are shown in the figure below. These are all housed in ElectricPrice.src and called from the *Finance* procedure.

Figure 38: Procedure Finance in ElectricPrice.src

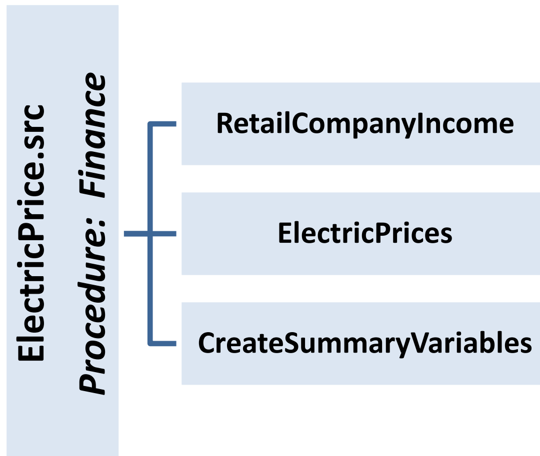


Table 54 provides a brief description of each of electric price procedures and identifies the key output variables. More detailed descriptions of these procedures are provided in the sections following the table.

Table 54. Description of Procedures within Electric Price

Procedure Description	Key Outputs
1. **RetailCompanyIncome** Determines total revenue for each retail company and saves the current retail price of electricity by economic class.	Revenue (RV, Rev); Price of electricity by class (PEClass)

Procedure Description	Key Outputs
2. ElectricPrices RECSPrice: Calculates impact of any renewable energy credits on retail price NonPowerCosts: Calculates impacts of any non-power costs on the retail price StrandedInvestments: Saves unit-level stranded investments for final price calculation ElectricPriceByECC: Determines final retail electric price as a function of price of power, delivery charges, and adjustments	Renewable impact on price (RnPE), Non-power costs (NPAC), Stranded investments (SICstPE), Calculated price of electricity (PECalc)
3. CreateSummaryVariables Aggregates and saves various retail company variables for use in the rest of the model and in model outputs	Sum contract costs (DACost), unit contract costs (UCConts)

Procedure RetailCompanyIncome

Revenue for each retail company is calculated by multiplying sales by the electric price. This procedure saves total revenue for each retail company and the average electric price by economic 'class', which refers to broad economic categories such as Residential, Commercial, etc.

RetailCompanyIncome Inputs and Outputs
Key Inputs
PE $_{ECC,ReCo,Year}$ = Marketer Price of Electricity ($/MWh)
SaCl $_{Class,ReCo,Year}$ = Electricity Sales (GWh/Yr)
SaEC $_{ECC,ReCo,Year}$ = Electricity Sales (GWh/Yr)
Key outputs
ECCRV (ECC,ReCo,Year) = Electricity Revenues (M$/Yr)
Rev $_{ReCo,Year}$ = Revenue (M$/Yr)

Key Equation: RetailCompany Income

Electricity revenues:

ECCRV=SaEC*PE/1000

Price of electricity by class:

PEClass=RV/SaCL*1000

Procedure ElectricPrices

The *ElectricPrices* procedure calculates the endogenous price of electricity for use throughout the rest of the model. The price of electricity is a function of the retail unit cost of purchasing electricity (PPUC), the delivery charge estimated during calibration of historical values (PEDC), taxes, and several adjustments dependent on the model parameters. These adjustments are calculated in sub-procedures before the final price estimation.

ElectricPrices Inputs and Outputs
Key Inputs
EEConv = Electric Energy Conversion (Btu/kWh)
$PPUC_{ReCo}$ = Unit Cost of Purchase Power ($/MWh)
$PEDC_{ECC,ReCo,Year}$ = Electric Delivery Charge ($/MWh)
$FPTax_{Prices,Area,Year}$ = Fuel Tax ($/mmBtu)
$FPSM_{Prices,Area,Year}$ = Energy Sales Tax ($/$)
Key outputs
$PECalc_{ECC,ReCo,Year}$ = Calculated Price of Electricity ($/MWh)

The delivery charge (PEDC) is calculated as part of the electric sector calibration via a comparison between the historically input values for electric prices versus the endogenous value. This value also contains other factors that aren't explicitly contained in other input variables for the final retail price, such as utility profit

RefundGratisToCustomers: If the user specifies that the value of gratis permits are granted to electric customers (GRefSwitch eq 1), then the cost of the emissions credit that is incorporated in the electric purchase price is removed from the final retail price. Gratis permits are permits that are granted freely to firms as part of an emissions permit regulatory system. This is in contrast to fixed price or auctioned permits, where a company would be required to purchase the permits required for emitting. If the simulation contains a permit regulatory system then ENERGY 2020 adds the cost of purchasing credits to every kilowatt-hour produced. If the user chooses to have the benefit of these gratis permits returned to the customer then the impact of the permits is subtracted back out when calculating the final retail price.

RECSPrice: The price impact of renewable energy credits is derived from the renewable requirement policy variable (RnFr), average costs of power for renewable units (ACE), and renewable electric generation (EGAGenCo). In response to a renewable portfolio standard, a retail company can choose to purchase electricity from renewable sources or purchase renewable credits. Activating the switch for this section of code (RECSwitch eq 1) assumes the latter and calculates the cost of the credit based on the renewable requirement (RnFr) to add to the final retail price.

NonPowerCosts: Other non-power costs are calculated from electric sales times the non-power unit cost variables (NPUC). This allows the user to specify the costs of producing any non-power goods and services that can be included in the final retail prices. Non-power costs can include overhead costs, human resources, and ancillary services produced by the utility. The unit cost variable is an exogenous input to the model that it set to zero as a default value.

StrandedInvestments: The unit level cost of stranded investments (SICstPE) is based on the stranded investment fraction (SICstFr) times the stranded costs per generating company (SICstG). Stranded investments refer to the amount of old debt that the company still needs to service from retired capital expenditures. Traditionally utilities often operated as monopolies with no competition, allowing for investments to assume a long depreciation schedule. Since there was no competition, a firm could plan on keeping a plant indefinitely as there was no reason to invest in new, more efficient generation. The onset of deregulation and regulation resulted in the need to replace old plants in order to produce power competitively. As a result, plants were put out of service before their initial outlay was fully paid meaning the investment is 'stranded', or not producing any power for the firm to sell. The cost of servicing this debt is not captured in the cost of purchasing power, so it is calculated separately and added to the final retail price.

The equation used to calculate the final retail price of electricity is listed below.

Key Equation: ElectricPrices

Calculated electricity price:

PECalc=(PPUC+NPAC+RnPE+SICstPE-GPURef+PEDC)*Infla
+∑(FPTax*EEConv/1000*SaECA)/SaEC*Infla) * (1+∑(FPSM*SaECA)/SaEC)

Model electricity price:

Do If ElecPrSw ne Exogenous
  PE=PECalc
Else
  PE=XPE*Infla