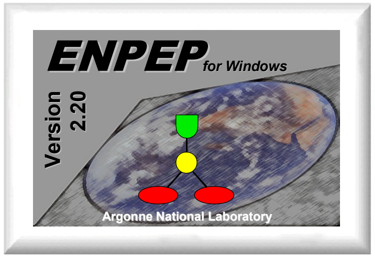
ENPEP-BALANCE: Expanded BALANCE Network with Electric Sector

ENPEP-BALANCE Training Course
Singapore
December 5-9, 2011



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As an Integrated Model,
BALANCE Captures Feedback Effects

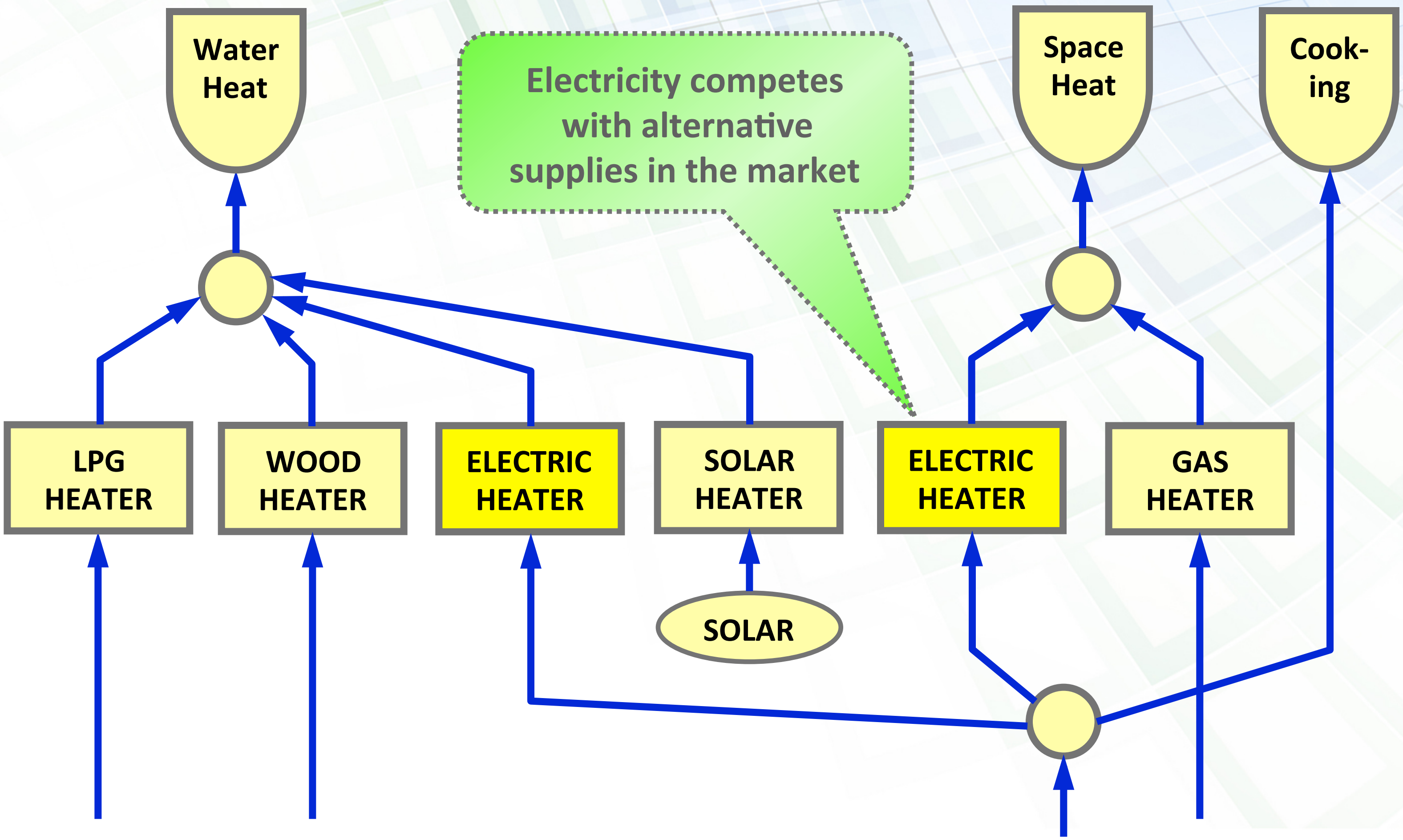
Electricity Price → Electricity Demand
- Substitutable
- Non-Substitutable

Electricity Demand → Fuel Price

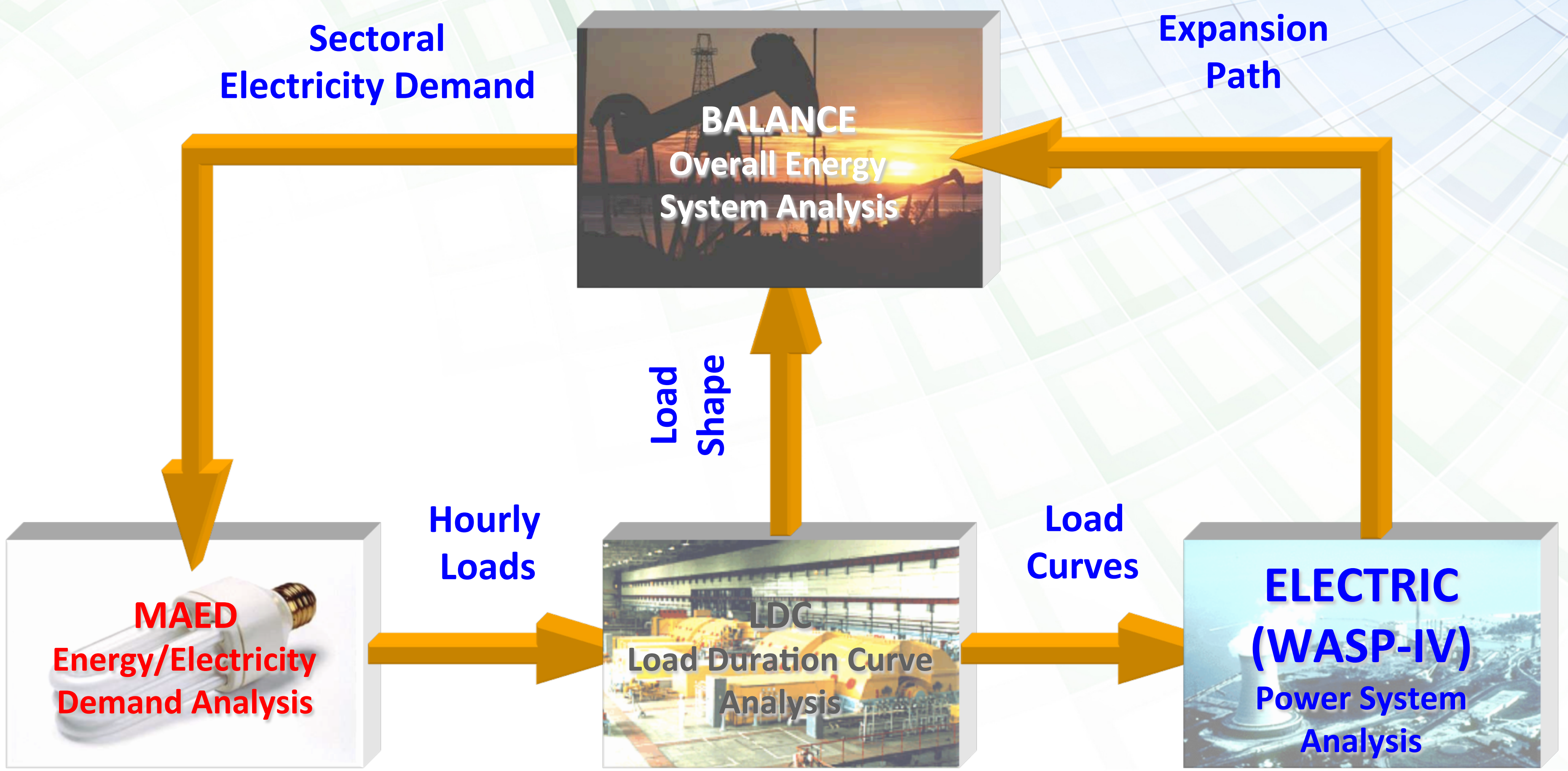
Electricity Demand → Capacity Expansion

Sector Effects

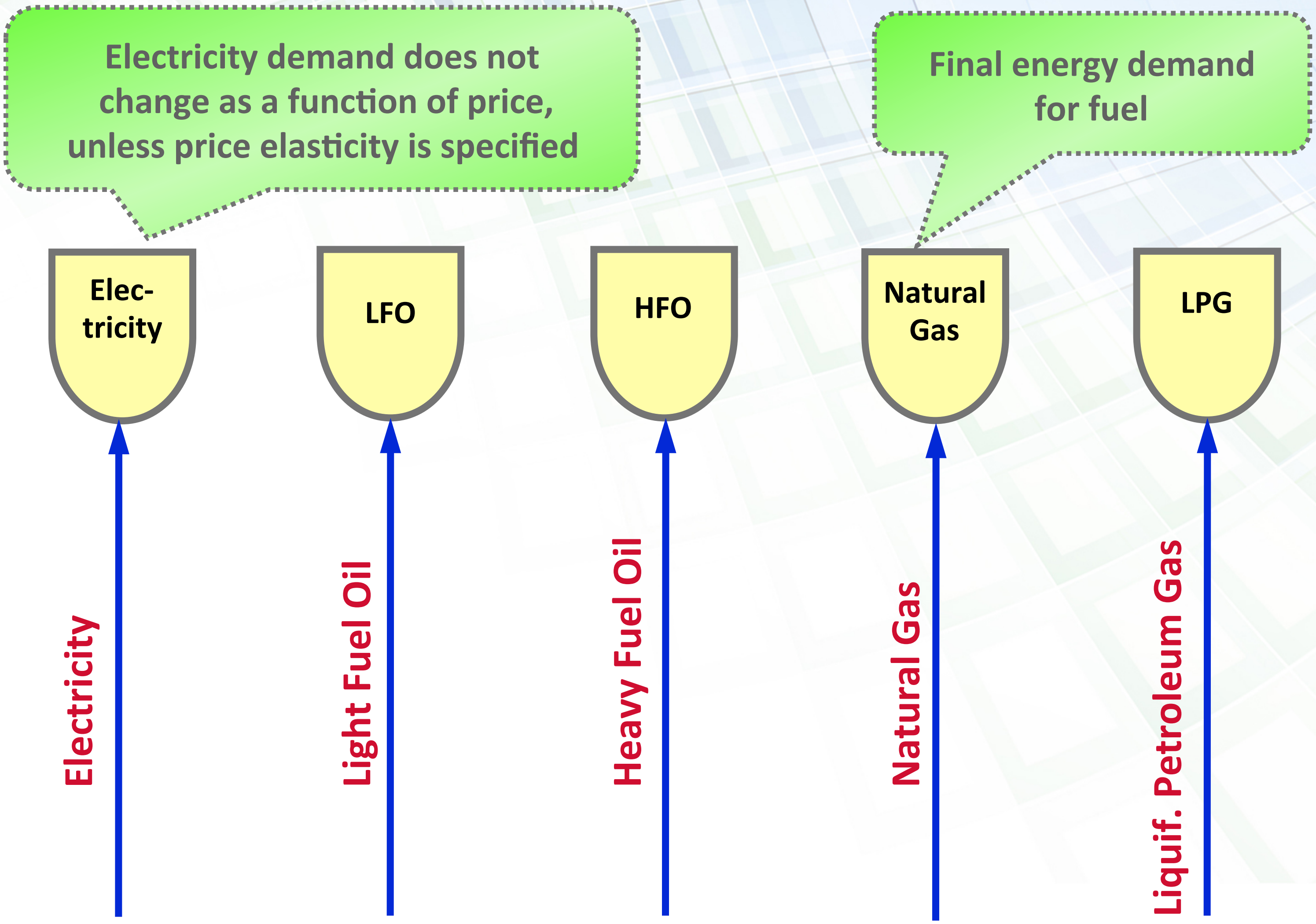
Variations in Electricity Demand Can Be Modeled in BALANCE using Useful Energy Demand Representation



When Electricity Demand Is Determined by BALANCE, Iterations With Other Models May Be Required



When Electricity Demand Is Exogenous, Iterations Are Typically Not Required



In BALANCE, there Are Three Main Methods for Representing the Electric Sector

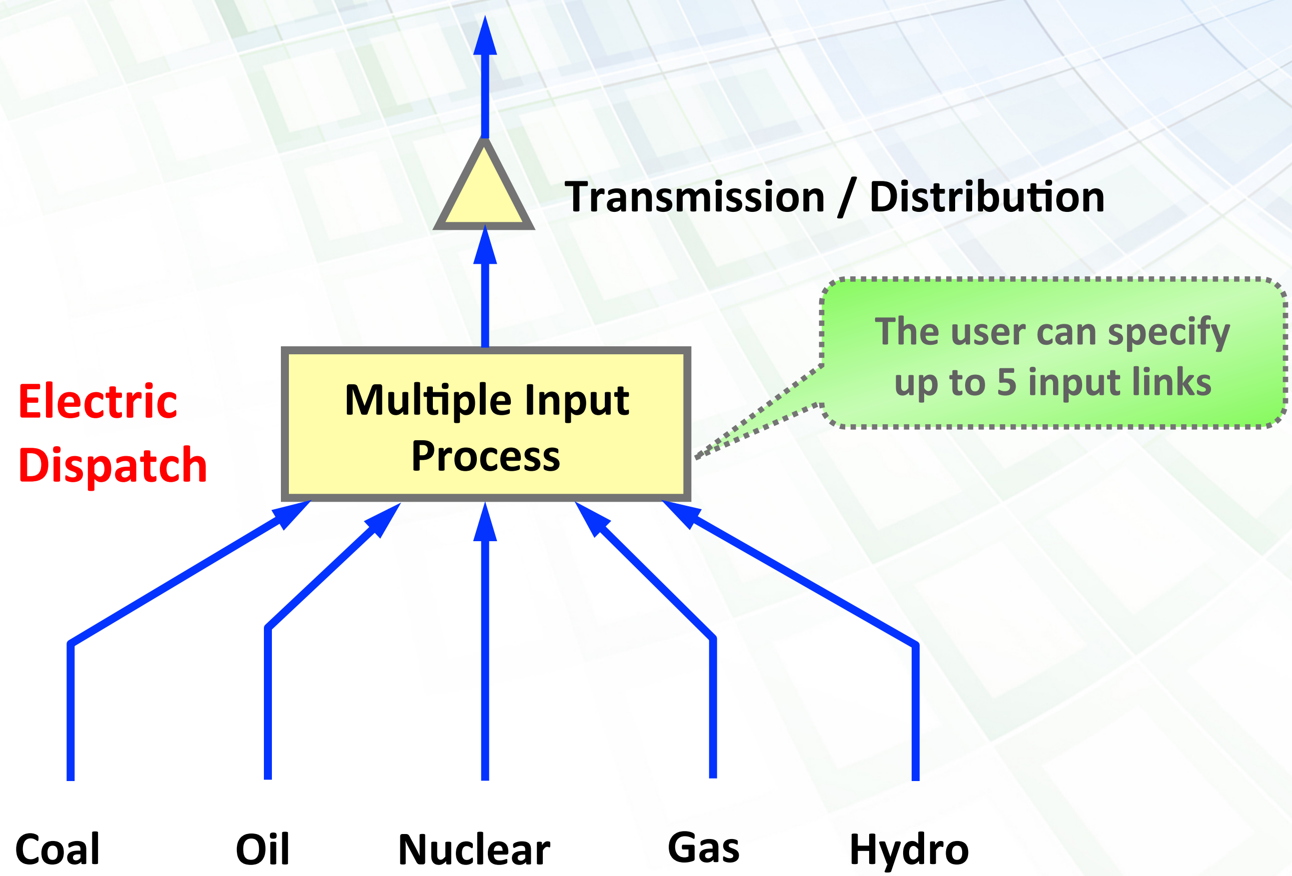
1. Multiple input process

2. Network of conversion processes and decision nodes

3. Electric sector submodule (with dispatch node)

The three different methods may also be combined

1. Simple Multiple Input Process Representation



Multiple Input Representation Data Requirements and Simulation Results

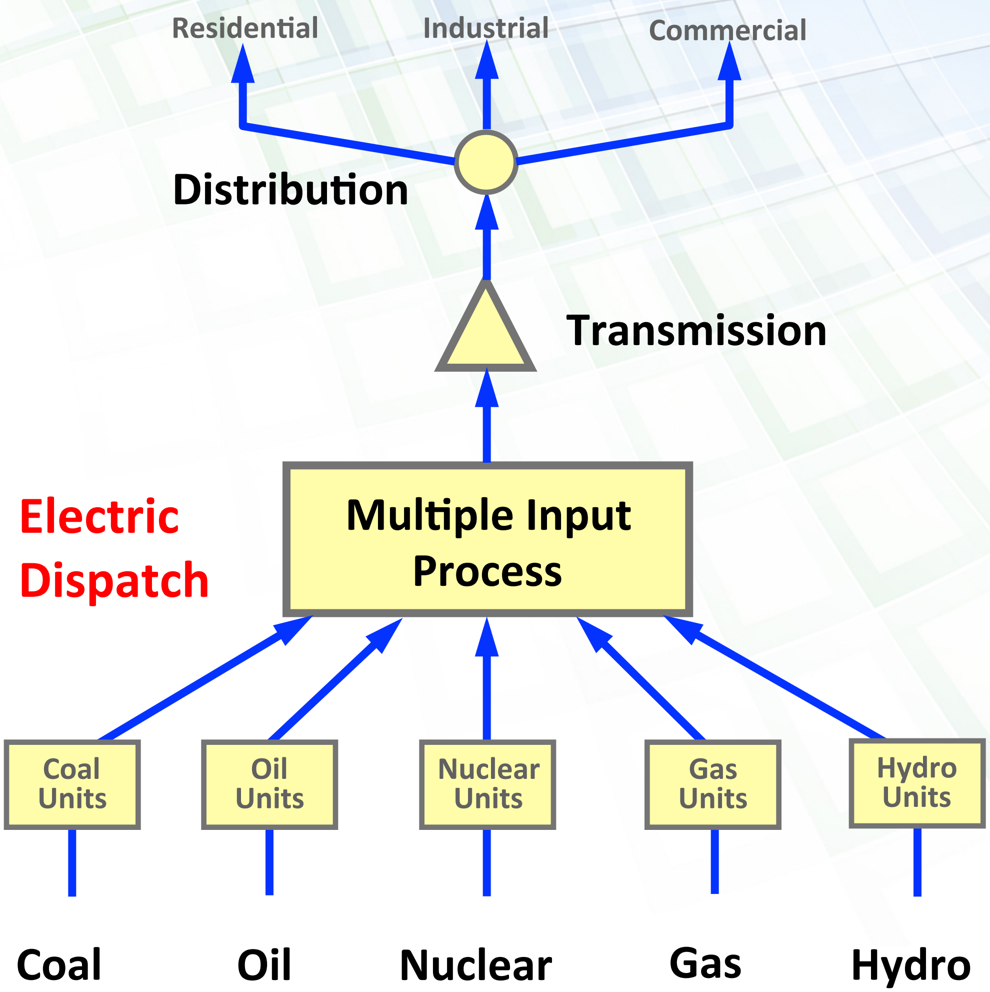
- User supplied information
  - Annual input/output ratios
  - Annual transmission and distribution losses

- Model results
  - Fuel use is scaled based on electricity demand

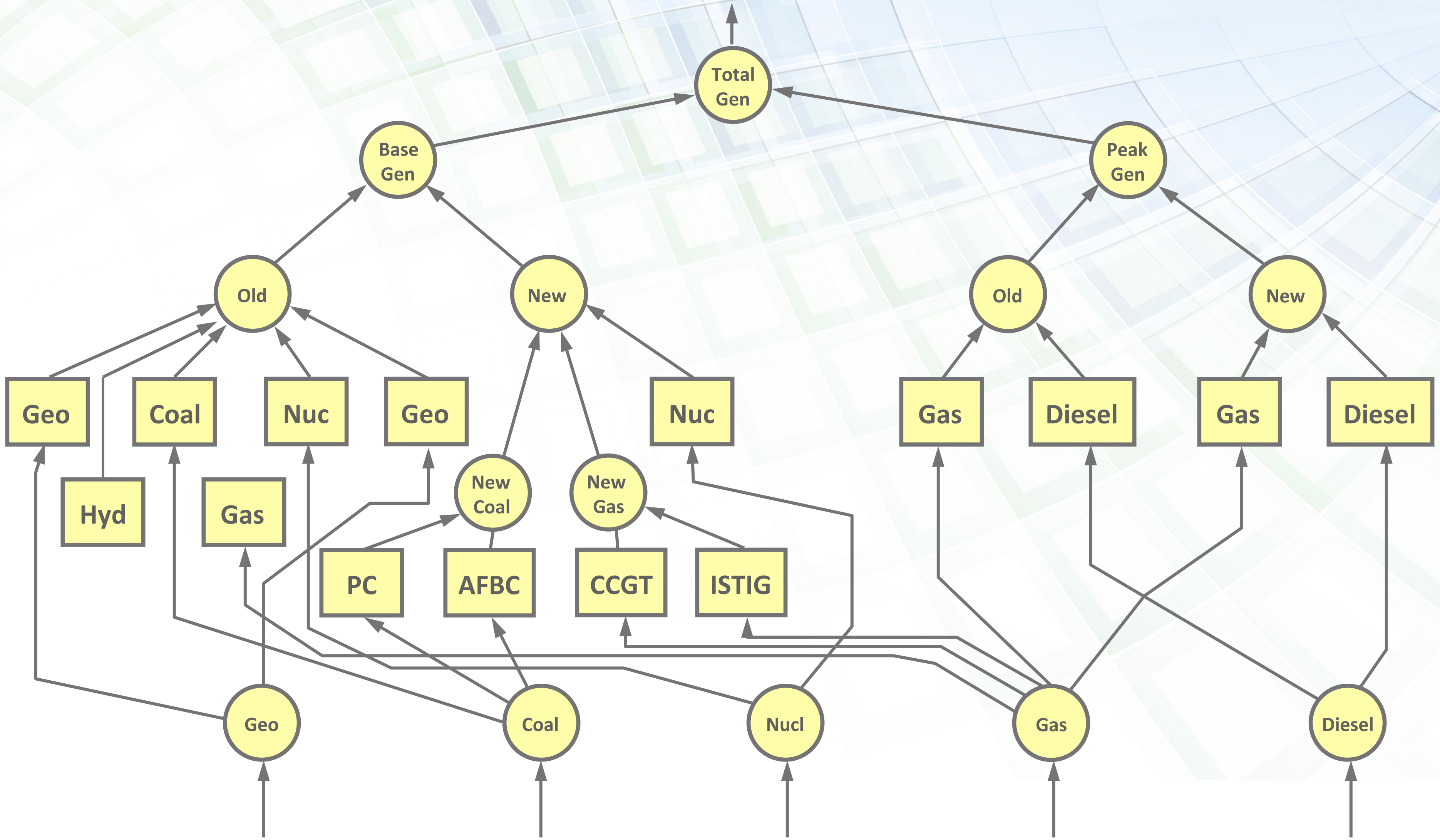
- Advantages
  - Accurate fuel consumption levels

- Disadvantages
  - Time required to iterate with expansion models
  - No adjustments of input fuel mix between iterations
  - Generation levels are scaled proportionally

Details Can Be Added to the Multiple Input Representation



2. BALANCE Can Represent the Electric Sector as a Set of Single Input/Output Process Nodes



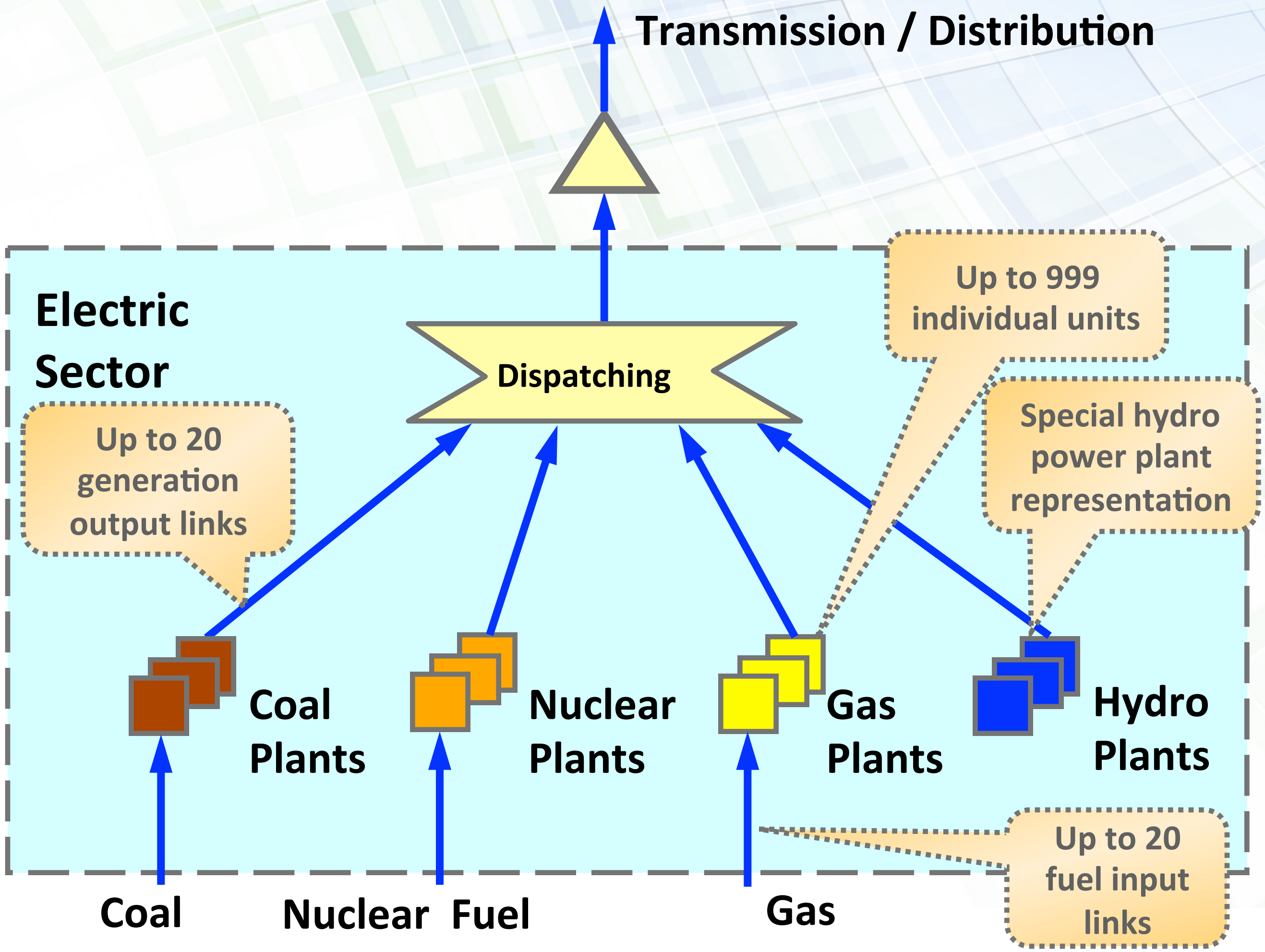
Process & Decision Node Representation Data Requirements and Simulation Results

- User supplied information
  - Detailed technology information
  - Data on generation levels for old resources
  - Response functions for decision nodes

- Advantages
  - Detailed capacity expansion models not required
  - Can run many scenarios quickly

- Disadvantages
  - Based on simple rules - not least cost
  - Unit-level dispatch not determined

3. The Electricity Dispatch Node Handles the Electric Sector in a Special Way



The Electric Dispatch Node Performs Several Important Functions

- Estimates unit-level capacity factors and unit-level and system-level power generation
- Estimates unit-level and system-level fuel consumption
- Adjusts capacity expansion timing
- Computes average electricity prices
- Interacts with fuel prices and electricity demand
- Time frame is annual
- Represents national power pool (on-grid)
- Expansion plan and unit alterations are specified by the user

Dispatch Node Representation Data Requirements and Simulation Results

- User supplied information
  - Detailed technology information
  - Capacity expansion path (from WASP or other power system expansion tool)

- Advantages
  - Annual expansion path is adjusted automatically
  - Adjustments are performed for each iteration

- Disadvantages
  - The dispatch is less detailed than in electric power system expansion models (e.g., WASP)
  - Peaking hydro is not simulated accurately
  - Adjusted expansion paths may not be optimal
  - Only one dispatch node can be used

BALANCE Can Simulate Complex Electric Sector Features

- Power Contracts
  - Minimum schedule requirement
  - Dispatchable contracts
  - Capacity limits
  - Energy limits
- Non-Dispatchable Capacity
  - Outside of the Electric Dispatch Submodule
- Cogeneration
  - Outside of the Electric Dispatch Submodule

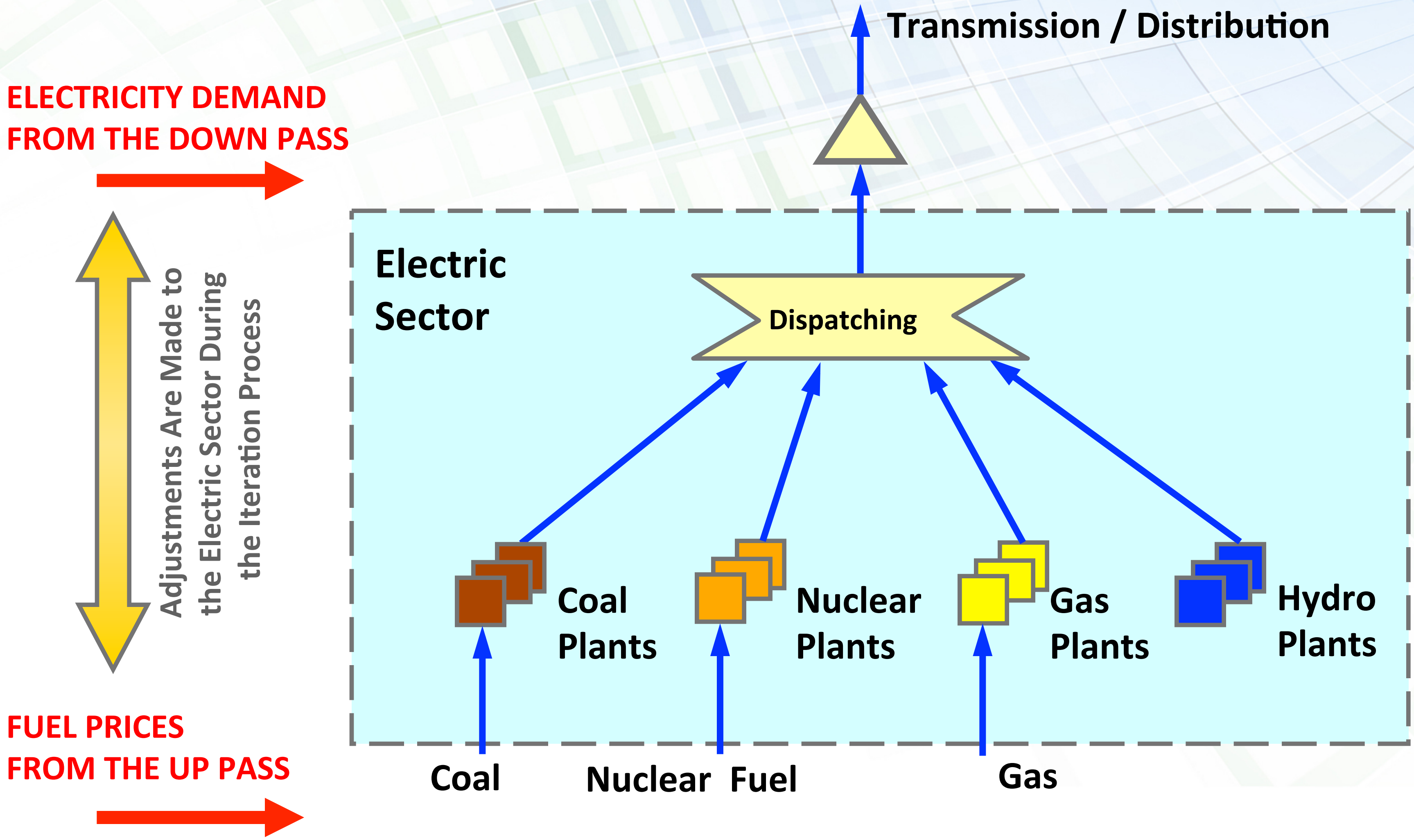
Complex Electric Sector Features (cont'd)

- On-grid and off-grid electricity demand should be normally separated

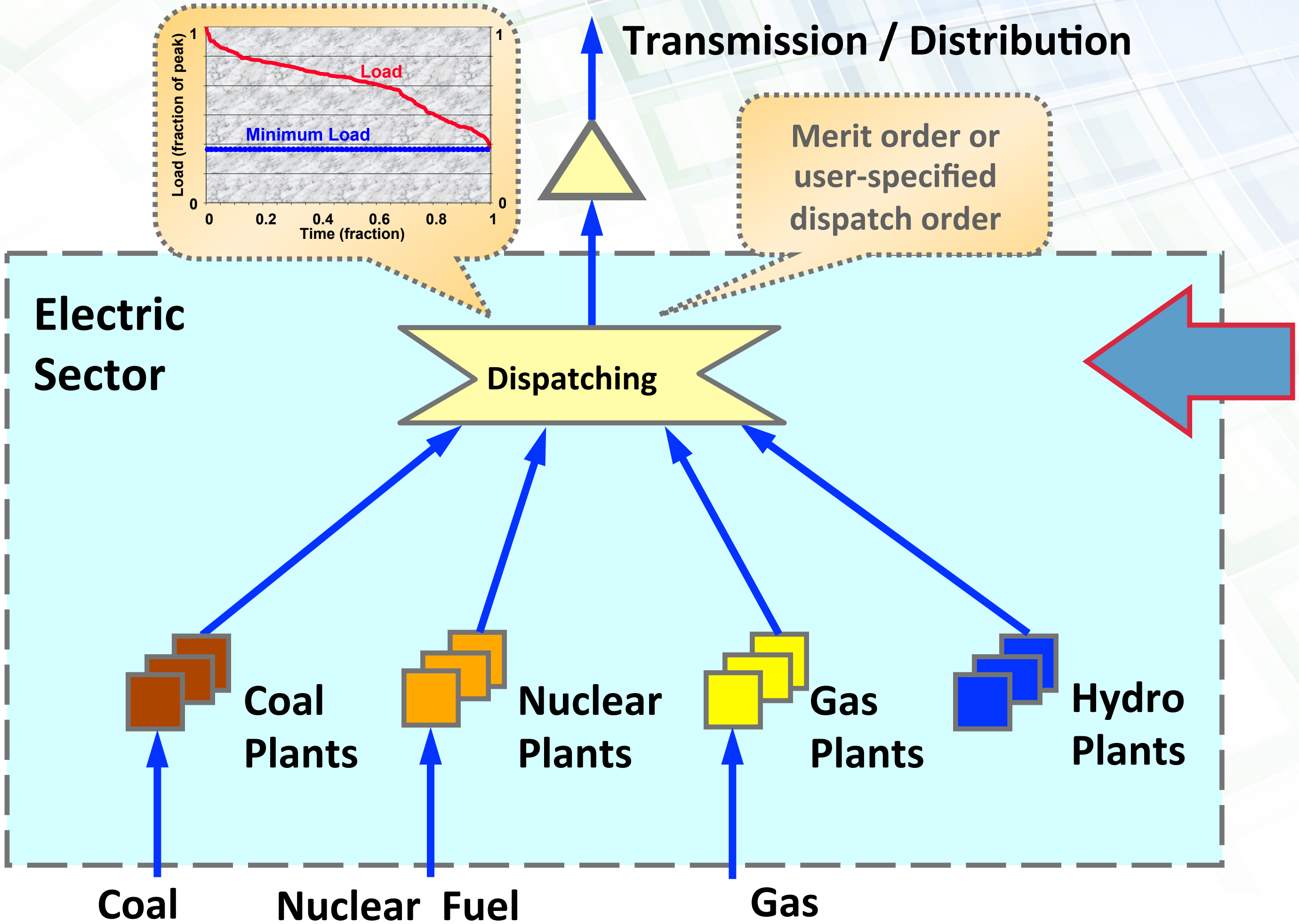
- Off-grid units and demand can be brought on-grid over time
  - Reflect timing in demand node growth rates
  - Decrease capacity off-grid
  - Use unit on-line date for units brought on to the grid

- User can alter unit dispatch
  - User specified loading order
  - Blocking (Two Unit Representation)
  - Non-economic dispatch (optional or user-specified dispatch)
  - Contract representation

Electricity Demand and Fuel Prices Are Received from the Network



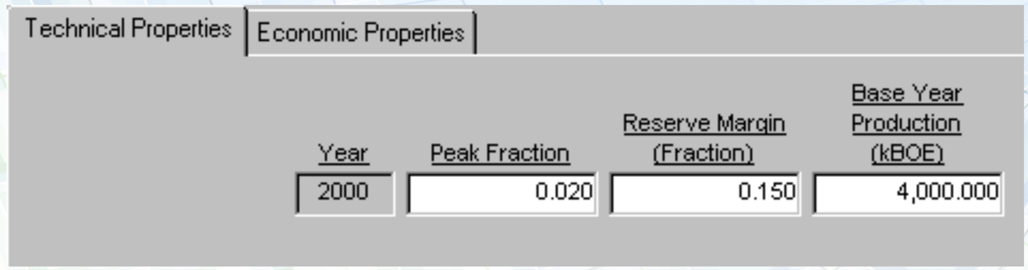
System Load Characteristics Are Input into BALANCE



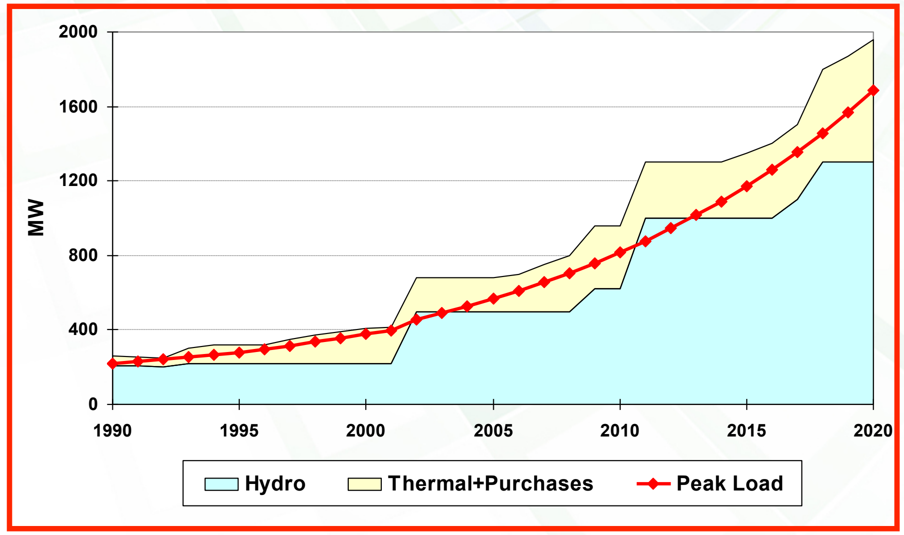
- Load Duration Curve Information
- Peak Fraction
- Reserve Margin

Dispatch Node Load Information Technical Properties

- ***Peak Fraction*** represents the fraction of electricity that the model will try to meet with peaking units only



- ***Reserve Margin*** represents the reserve margin for the electric sector of your network
  - 0.15 equals 15% reserve margin over peak demand
  - Is used only for simple reserve margin check; warning message issued if system cannot meet reserve requirement



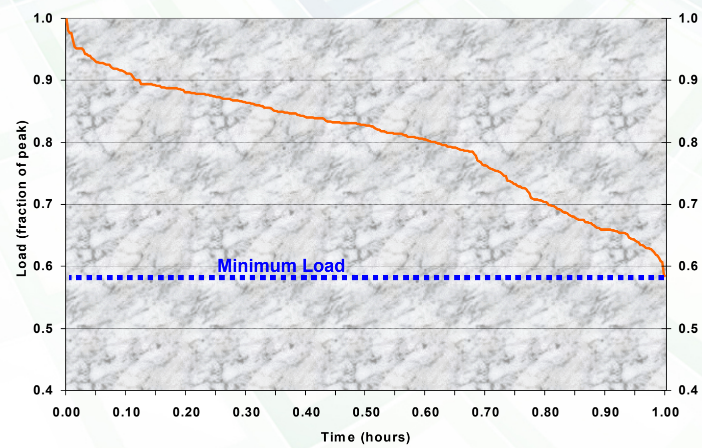
- ***Base-Year Production*** represents the base-year electricity generation

Dispatch Node Load Information Economic Properties

- ***Interest Rate*** represents the annual interest rate used for levelizing (amortizing) the capital cost of electric generating units (cost of capital);
- ***Minimum Annual System Load*** is used in conjunction with the Snyder approximation method for the annual load duration curve; it is a fraction of the annual peak load
- ***Annual Average Load Factor*** is used in conjunction with the Snyder approximation method
- ***Inverse LDC Number of Cells*** represents the number of cells used to approximate the inverse load duration curve; this value must range from 1 to 50

Technical Properties | Economic Properties

Year	Interest Rate (Fraction)	Minimum Annual System Load (Fraction)	Annual Average Load Factor (Fraction)	Inverse LDC Number of Cells	LDC Approx. Method
2000	0.080	0.396	0.680	30	Snyder
2001					Polyn.
2002					Snyder



Dispatch Node Load Information Economic Properties (cont'd)

- ***LDC Polynomial Coefficients*** are used if you choose the polynomial LDC approximation method; in this case the model uses a fifth-degree polynomial to represent the annual load duration curve

Technical Properties | Economic Properties

Year	Interest Rate (Fraction)	LDC Polyn. Coeff. 0	LDC Polyn. Coeff. 1	LDC Polyn. Coeff. 2	LDC Polyn. Coeff. 3	LDC Polyn. Coeff. 4	LDC Polyn. Coeff. 5	Inverse LDC Number of Cells	LDC Approx. Method
2000	0.080	1.000	-1.932	8.400	-22.200	25.650	-10.614	30	Polyn.
2001									
2002									

- There are six coefficients for the fifth-degree polynomial equation that forms the annual load duration curve; the ***first coefficient (a0)*** must be 1.0

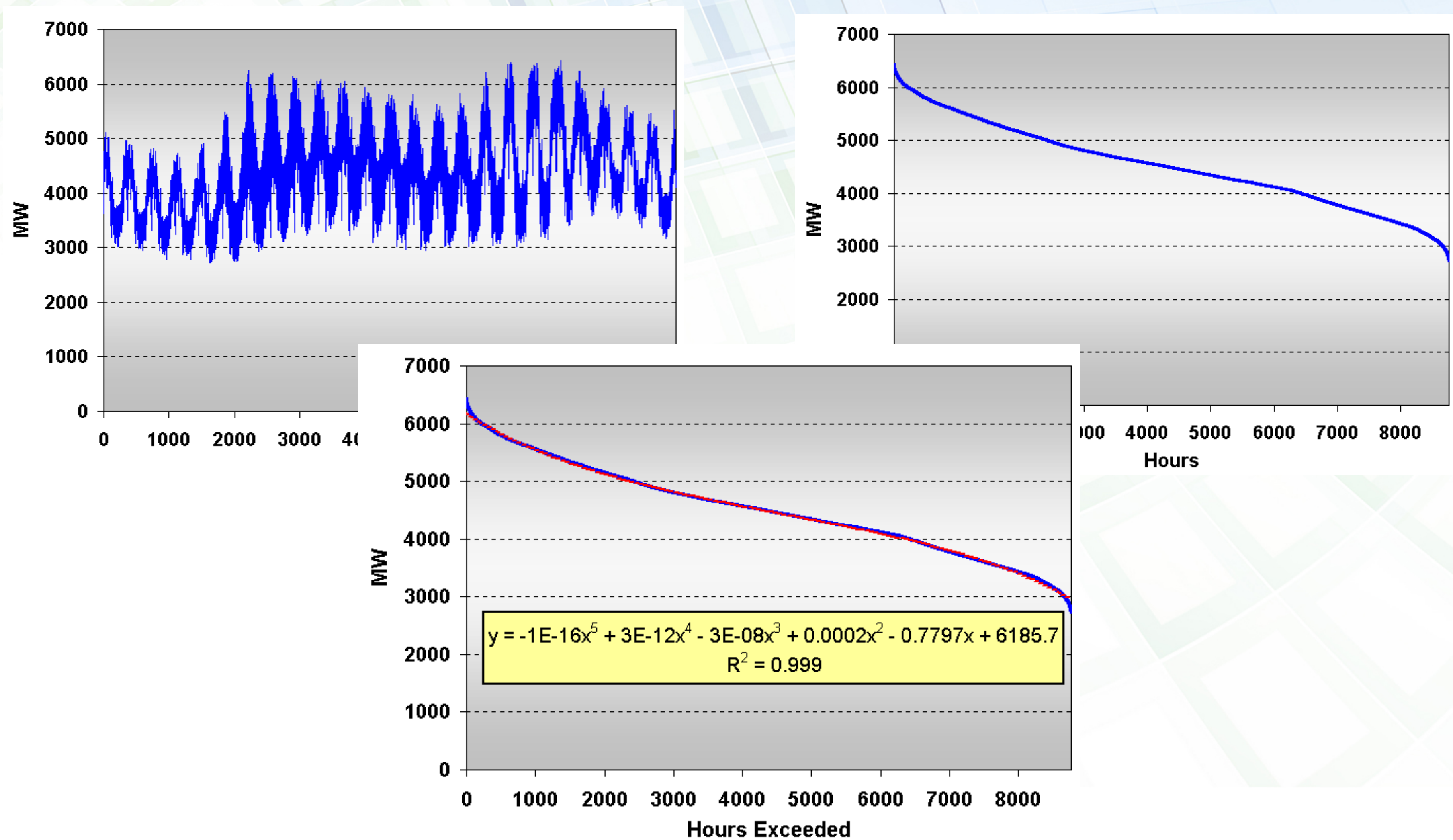
- ***Inverse LDC Number of Cells*** represents the number of cells used to approximate the inverse load duration curve; this value must range from 1 to 50

- You may obtain the coefficients from EXCEL if you have hourly chronological loads or from the WASP case

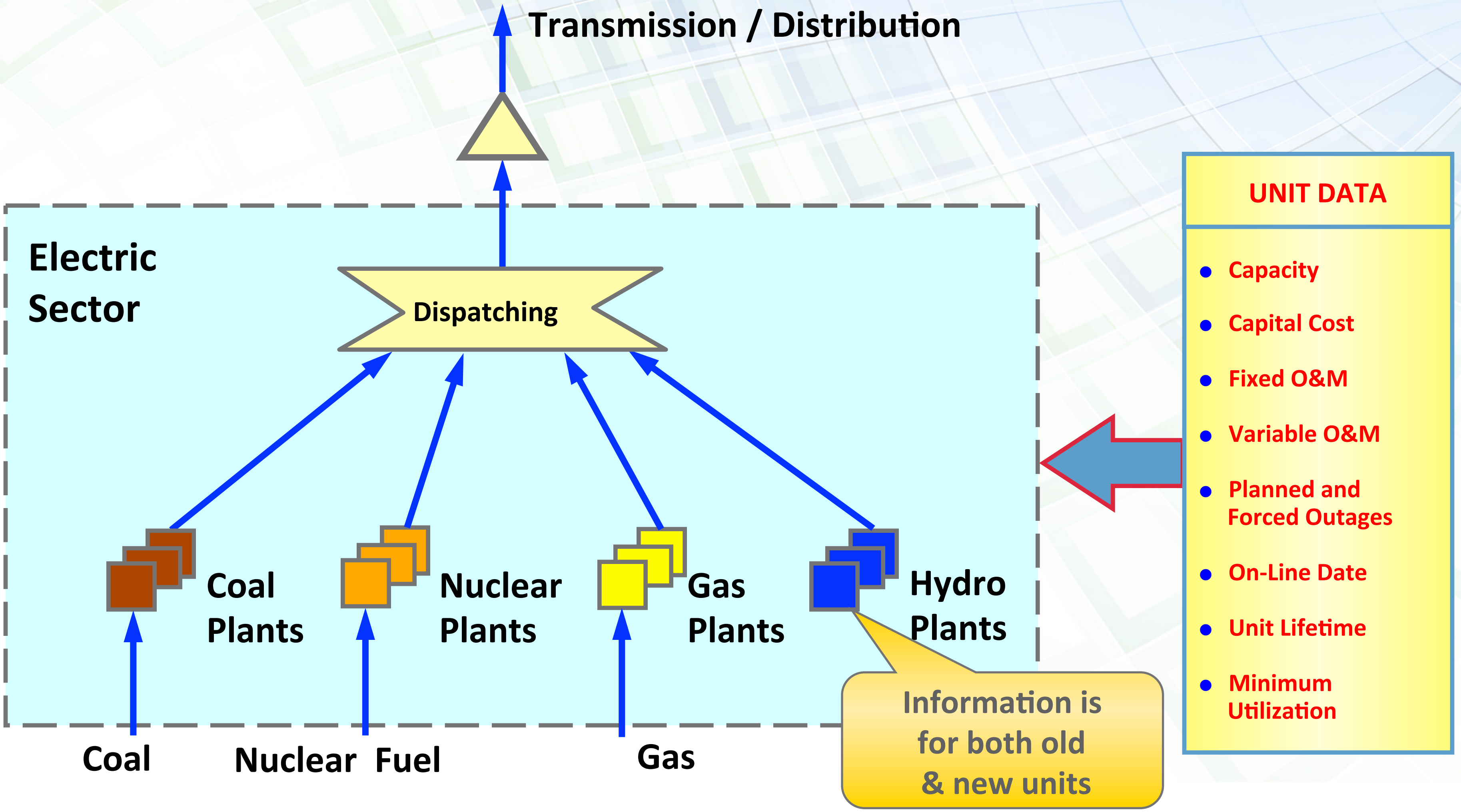
Steps Involved in Creating a Load Curve Duration

- Collect hourly load data
- Create a cumulative curve (annual)
- Approximate the curve
  - Option A. Fifth-degree polynomial
    - Use EXCEL data graph trendline feature
  - Option B. Snyder method

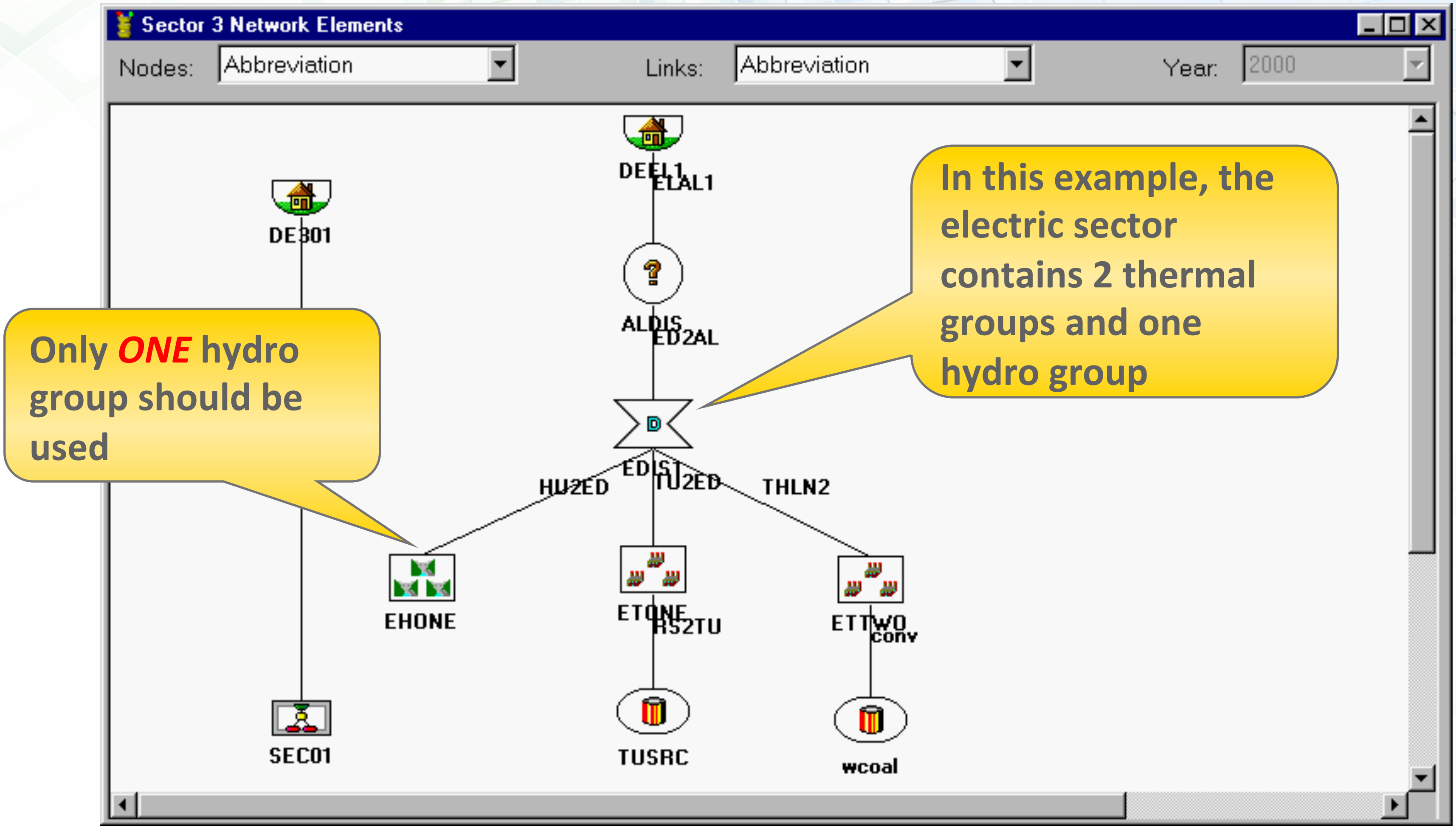
Steps Involved in Creating a Load Curve Duration



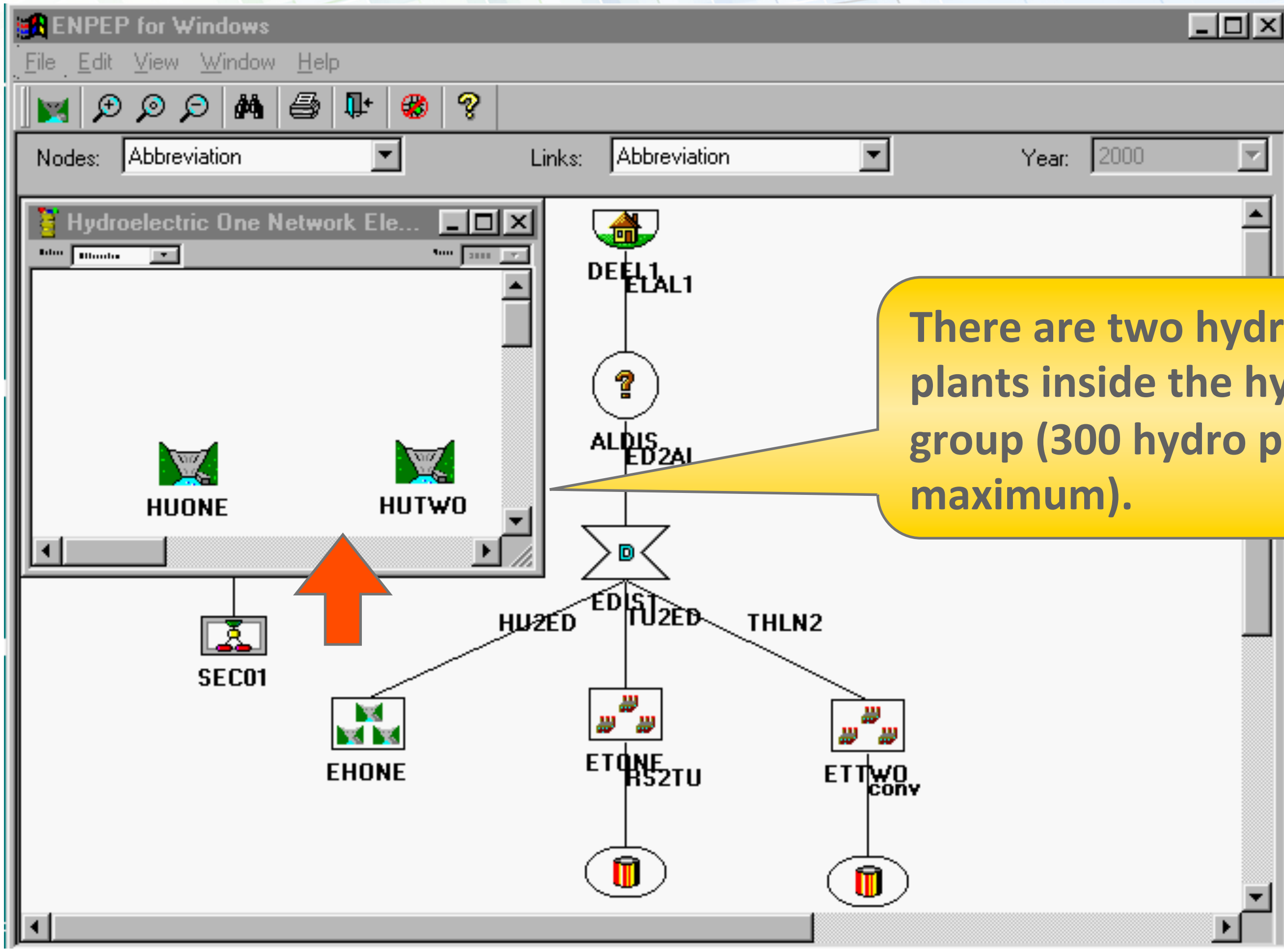
Data on Individual Power Plants Are Input into BALANCE



Generating Units are Organized into Groups: Total of Up to 20 Goups (1 Hydro + 19 Thermal)

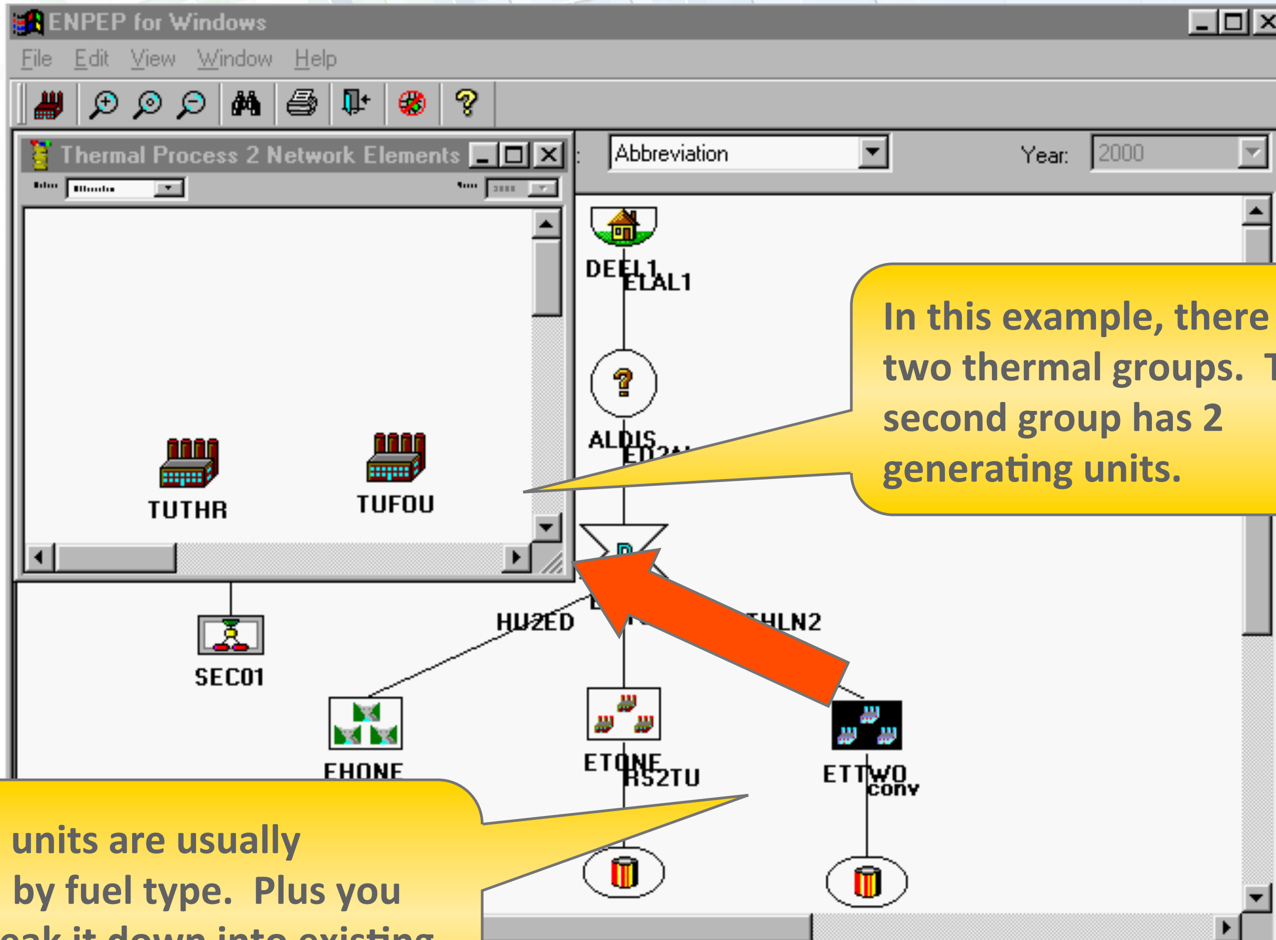


The SINGLE Hydro Group can Contain up to 300 Individual Hydro Plants



There are two hydro power plants inside the hydro group (300 hydro plants maximum).

There Can be up to 19 Thermal Groups with a Total of 999 Generating Units



In this example, there are two thermal groups. The second group has 2 generating units.

Thermal units are usually grouped by fuel type. Plus you could break it down into existing units and new units

Electric Thermal Unit Data Technical Properties

Technical Properties | Economic Properties

Year	Optional Loading Order ($/MWh)	Capacity (MW)	Heat Rate (BTU/kWh)	Unplanned Outage Rate (Fraction)	Planned Outage Rate (Days/Year)	Minimum Annual Utilzation Rate (Fraction)
2000	2.000	300.000	10,500.000	0.045	35.000	0.000
2001					40.000	
2002						

- ***The Optional Loading Order*** overrides the economic dispatch. A blank indicates that the economic order will be used
- ***Unplanned Outage Rate*** is the fraction of time the unit is expected to be on forced outage; will be used to derate the unit capacity
- ***Planned Outage Rate*** is the number of days the unit is on scheduled maintenance; will be used to derate the unit capacity
- ***Minimum Annual Utilization Rate*** is the minimum capacity factor acceptable for this unit. The unit will not be dispatched if the model estimates that the unit will be utilized below the specified value
  - Use 0 for peaking units
  - Use 0.2 or higher for base load units

Electric Thermal Unit Data Economic Properties

Technical Properties | Economic Properties

Year	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-Year)	Variable O&M Cost ($/MWh)	Life Expectancy (Years)	On-line Date (Year)
2000	1,000.000	40.000	0.850	25	2000
2001					

- ***Capital Costs*** should only be used if costs are included in the rate base;
- ***Life Expectancy*** is the economic life-time and is used to levelize capital costs and also to retire a unit based on the on-line date (maximum value 99 years);
- A unit is typically not dispatched before its on-line date. However, adjustments are made based on load growth and reserve margin requirements.

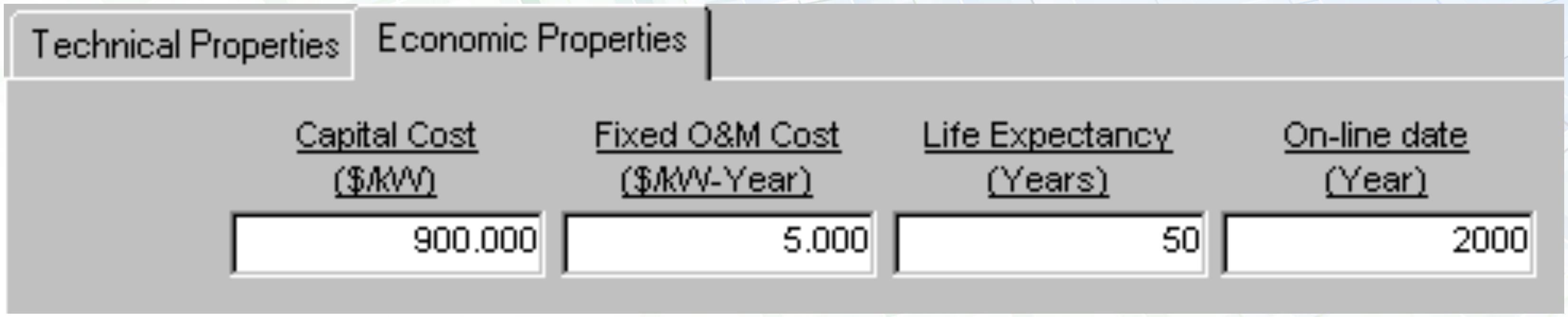
Electric Hydro Unit Data
Technical Properties

Technical Properties | Economic Properties

Year	Optional Loading Order ($/MWh)	Capacity (MW-Year)	Unplanned Outage Rate (Fraction)	Planned Outage Rate (Days/Year)	Minimum Annual Utilzation Rate (Fraction)
2000	1.250	100.000	0.000	0.000	0.000
2001					

- By default, hydro units are loaded in the base portion of the load duration curve as they have 0 total variable cost
- The ***Optional Loading Order*** can be used to move hydro units into the peak part of the curve; however, generation levels need to be verified
- The ***Capacity*** of hydropower plant is specified as the annual generation (MWh/yr) divided by the number of hours in a year (i.e., 8760).

Electric Hydro Unit Data
Economic Properties



- ***Capital Costs*** should only be specified if costs are included in the electricity rate base;
- ***Life Expectancy*** is the economic lifetime and is used to levelize capital costs and also to retire a unit based on the on-line date (maximum value 99 years);
- A unit is typically not dispatched before its on-line date. However, adjustments are made based on load growth and reserve margin requirements.

How Does the Model Load the Units and Estimate Unit Capacity Factors and Generation Levels

- STEP 1: Derate units before loading
- STEP 2: Compute the loading order (taking into account user-specified loading order)
- STEP 3: Enter units into the load duration curve
- STEP 4: Determine the number of hours of operation and annual generation for each unit

STEP 1: Derate Units Before Loading

- Account for scheduled maintenance
- Account for equivalent forced outages

$$\begin{matrix}\mathit{Derated}\\\mathit{Capacity}\end{matrix} = \begin{matrix}\mathit{Installed}\\\mathit{Capacity}\end{matrix}\ x\ \left(1 - \begin{matrix}\mathit{Unplanned}\\\mathit{Outage\,Rate}\end{matrix}\right)\ x\ \left(1 - \frac{\mathit{Planned\ Outage}}{365}\right)$$

EXAMPLE

Installed Capacity:	**400 MW**
Unplanned outage rate:	**15% per year**
Planned outage:	**35 days/year**

$$400\,MW\ x\ (1 - 0.15)\ x\ \left(1 - \frac{35}{365}\right) = 307.4\,MW$$

STEP 2: Compute the Loading Order: Loading Order Is Based on Total Variable Cost

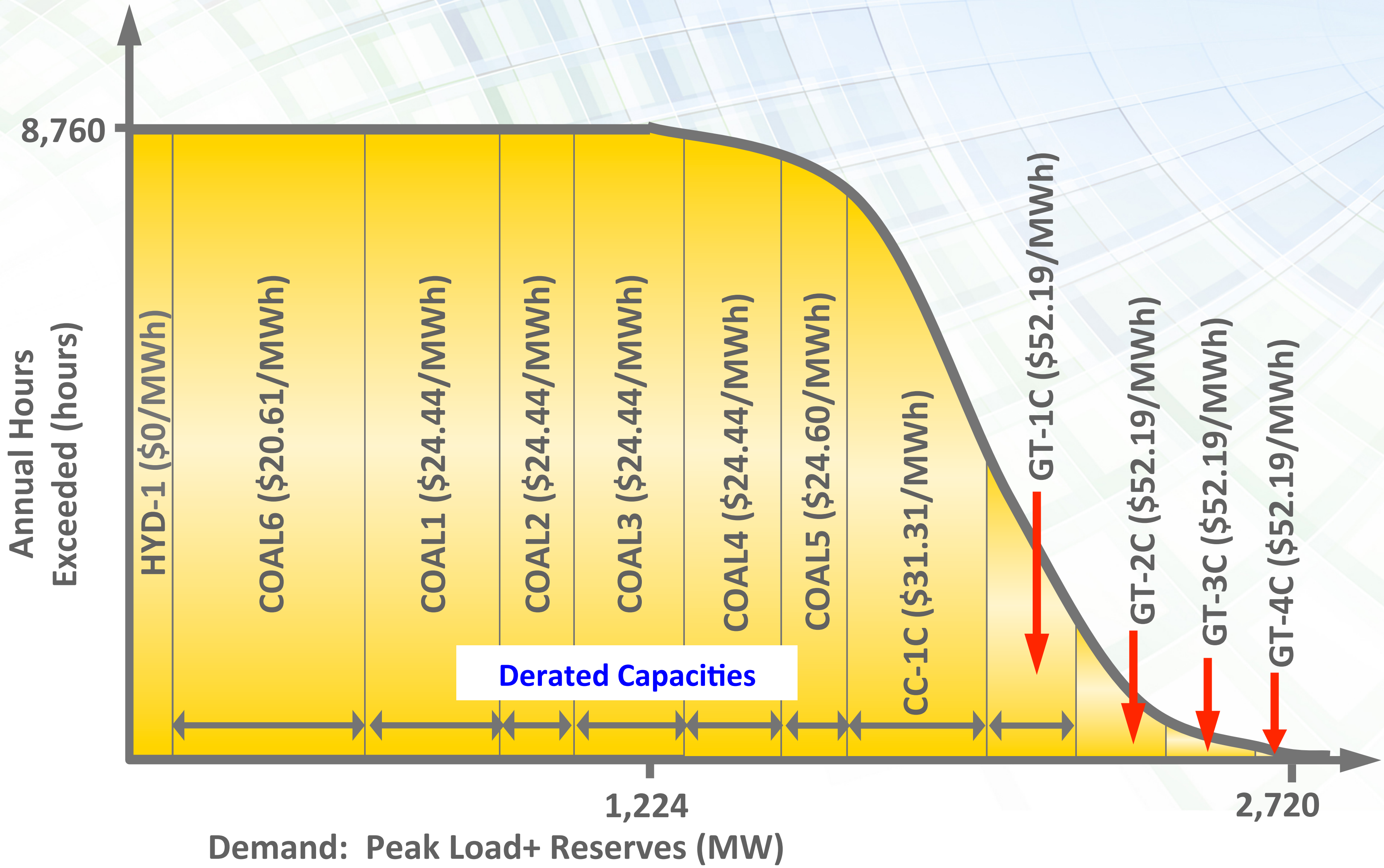
$$Variable\ Cost_{Total} = Variable\ O\&M + \left(\frac{Fuel\ Price\ \ x\ \ Heat\ Rate}{5,440.761} \right)$$

EXAMPLE

Variable O&M cost:	3.3 $/MWh
Fuel Price:	10 $/boe
Heat rate:	9,800 btu/kWh
Unit conversion factor:	5,440.761 (5,440,761 btu/boe x 0.001 MWh/kWh)

$$3.3 + \left(\frac{10\ \ x\ \ 9,800}{5,440.761} \right) = 21.3122\ \$/MWh$$

STEP 3: Enter Units into the Load Duration Curve, First Hydro Units, then Continue with Lowest Variable Cost Thermal Units



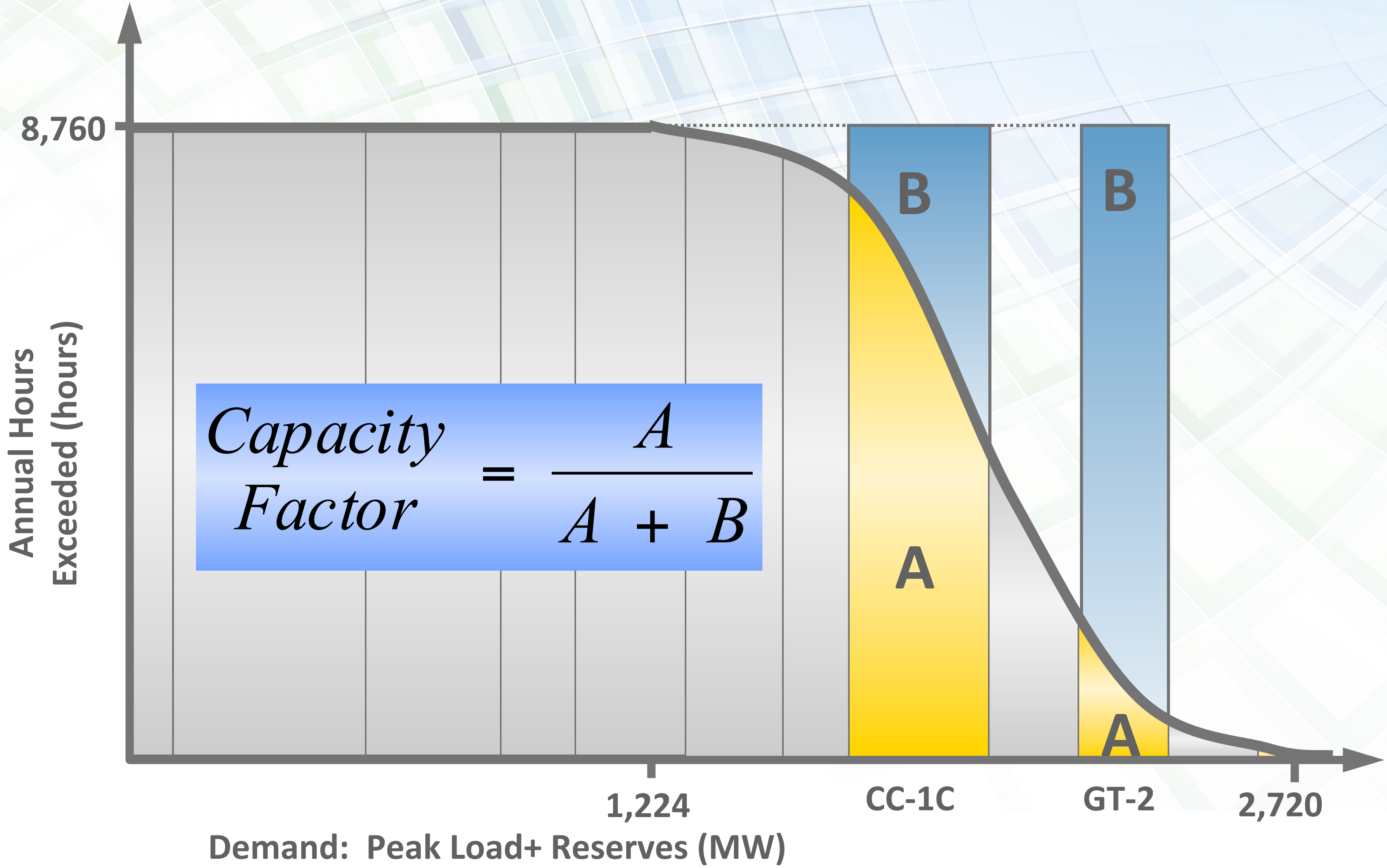
STEP 3: Enter Units Into the Load Duration Curve: Dispatch Node Report

Unit loading order ranked by total variable cost

Derated Capacities

UNIT NAME	OPTIONAL LD ORDER	UNIT V COST $/MWH	UNIT F COST $/MW	YEAR BUILT	UNIT CAPAC MW	UNIT UTIL	UTIL MIN	ENERGY IN 10*3 BOE	UNIT ENERGY MWH
HYD-1	0.0000	0.0000	413437	1990	93.97	0.94	0.00	516.29	823197
Coal6	0.0000	20.6119	127257	1995	461.10	0.77	0.20	6990.59	4038820
NCoal	0.0000	21.3122	131157	2007	307.40	0.77	0.20	4848.89	2692536
Coal1	0.0000	24.4368	22850	1971	315.62	0.70	0.20	5842.15	2764526
Coal2	0.0000	24.4368	22850	1971	175.34	0.68	0.20	3147.17	1489252
Coal3	0.0000	24.4368	33076	1981	258.66	0.48	0.20	3126.06	1479261
Coal4	0.0000	24.4368	131157	1991	230.55	0.38	0.20	2135.58	1010565
Coal5	0.0000	24.5988	131157	1991	153.70	0.23	0.10	779.97	404234
CC-1C	0.0000	31.3102	60218	1999	330.41	0.09	0.05	452.79	320543

STEP 4: Determine Unit Capacity Factor



$$\text{Capacity Factor} = \frac{A}{A + B}$$

STEP 4: Determine Unit Capacity Factor: Dispatch Node Report

Capacity Factor (based on installed capacity)

UNIT NAME	OPTIONAL LD ORDER	UNIT V COST $/MWH	UNIT F COST $/MW	YEAR BUILT	UNIT CAPAC MW	UNIT UTIL	UTIL MIN	ENERGY IN 10*3 BOE	UNIT ENERGY MWH
HYD-1	0.0000	0.0000	413437	1990	93.97	0.94	0.00	516.29	823197
Coal6	0.0000	20.6119	127257	1995	461.10	0.77	0.20	6990.59	4038820
NCoal	0.0000	21.3122	131157	2007	307.4[illegible]	0.77	[illegible].20	4848.89	2692536
Coal1	0.0000	24.4368	22850	1971	[illegible]5.62	0.70	0.20	5842.15	2764526
Coal2	0.0000	24.4368	[illegible]	[illegible]	175.34	0.68	0.20	3147.17	1489252
Coal3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]58.66	0.48	0.20	3126.06	1479261
Coal4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]30.55	0.38	0.20	2135.58	1010565
Coal5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]53.70	0.23	0.10	779.97	404234
CC-1C	0.0000	31.3102	60218	1999	330.41	0.09	0.05	452.79	320543

$$\frac{2{,}692{,}536\ MWh}{400\ MW_{installed}\ \ x\ \ 8{,}760\ h} = 0.77$$

Exceptions to Economic Loading Order: Use the Optional Loading Order to Move Units in Desired Place

- Must run units
- Peak hydroelectric units
- Non-dispatchable units
  - Wind
  - Solar
  - Run-of-river hydro
- Spinning reserves
  - Block units

Calculate Fixed Cost

$$\text{Fixed Cost}_{Total} = \left(\text{Capital Cost} \; x \; CRF + \text{Fixed } O\&M \right) x \; 1000$$

EXAMPLE

Capital Cost:	1,021
Fixed O&M cost:	22.85 $/kW-year
Unit Life Time:	30 years
Interest Rate:	0.1 (fraction)

$$CRF = \frac{i \; x \; (1 + i)^n}{(1 + i)^n - 1}$$

Capital Recovery Factor: $$\frac{0.1 \; x \; (1 + 0.1)^{30}}{(1 + 0.1)^{30} - 1} = 0.10608$$

$$(1{,}021 \; x \; 0.10608 + 22.85) \; x \; 1{,}000 = 131{,}157 \; \$ / MW / year$$

Calculate Unit Generation and Fuel Consumption

$$Generation = \begin{matrix} Derated \\ Capacity \end{matrix} \; x \; \begin{matrix} Capacity \\ Factor \end{matrix} \; x \; 8760$$

$$\begin{matrix} Fuel \\ Consumption \end{matrix} = Generation \; x \; \frac{Heat\ Rate}{5{,}440{,}761}$$

EXAMPLE

Derated Capacity:	**307.3973 MW**
Capacity Factor:	**0.77 (0.768418)**
Heat Rate:	**9,800 btu/kWh**
Unit Conversion Factor:	**5,440,761 btu/boe**

$$307.3973\ MW \;\; x \;\; 0.768418 \;\; x \;\; 8760\ h \; = \; 2{,}692{,}537\ MWh$$

$$2{,}692{,}537\ MWh \;\; x \;\; \frac{9800\ btu/kWh}{5{,}440{,}761} \; = \; 4{,}849.8\ kboe$$

Fixed Cost, Generation, and Fuel Consumption: Dispatch Node Report

Unit Fixed Cost

Unit Fuel Consumption (Energy In) and Generation (Unit Energy)

UNIT NAME	OPTIONAL LD ORDER	UNIT V COST $/MWH	UNIT F COST $/MW	YEAR BUILT	UNIT CAPAC MW	UNI[illegible] UTIL	[illegible]IL MI[illegible]	ENERGY IN 10*3 BOE	UNIT ENERGY MWH
HYD-1	0.0000	0.0000	413437	1990	93.97	0.94	0.00	516.29	823197
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Calculate Unit Generation Cost

$$\text{Generation Cost}_{Total} = \left(\text{Fixed Cost}_{Total} \; x \; \text{Installed Capacity}\right) + \left(\text{Variable Cost}_{Total} \; x \; \text{Generation}\right)$$

EXAMPLE

Fixed Cost Total:	**131,157 \$/MW-year**
Installed Capacity:	**400 MW**
Variable Cost Total:	**21.3122 \$/MWh**
Generation:	**2,692,536 MWh**

$$131{,}157 \;\; x \;\; 400 \; + \; 21.3122 \;\; x \;\; 2{,}692{,}536 \; = \; 109{,}846{,}666 \; \$ / \, year$$

Model reports cumulative cost: 310.79 - 200.95 = 109.84 million

UNIT NAME	CUM COST 10*6 \$
HYD-1	41.34
Coal6	200.95
NCoal	310.79

Calculation of Average Electricity Cost/Price (AEC)

$$AEC = \frac{\sum Generation\ Cost_{Total}}{\sum Generation}$$

At the end of each iteration, model also summarizes capacity, demand, reserves

TOTAL ELECTRICITY DEMAND (MWH)	=	15170319
EST. ELECTRICITY SUPPLY (MWH)	=	15182986
RATIO SUPPLY/DEMAND (FRAC)	=	1.0008
AVAIL DERATED CAPACITY (MW)	=	3197.16
CAPACITY EXISTING UNITS (MW)	=	3197.16
CAPACITY PRODUCING UNITS (MW)	=	2979.55
PEAK DEMAND (MW)	=	2886.29
COMPUTED RESERVE MARGIN ()	=	10.77
TOTAL GENERATION COST ($)	=	662156800.00000
AVE. ELECTRICTY COST (c/KWH)	=	4.3612
LARGEST VAR COST (c/KWH)	=	5.2188

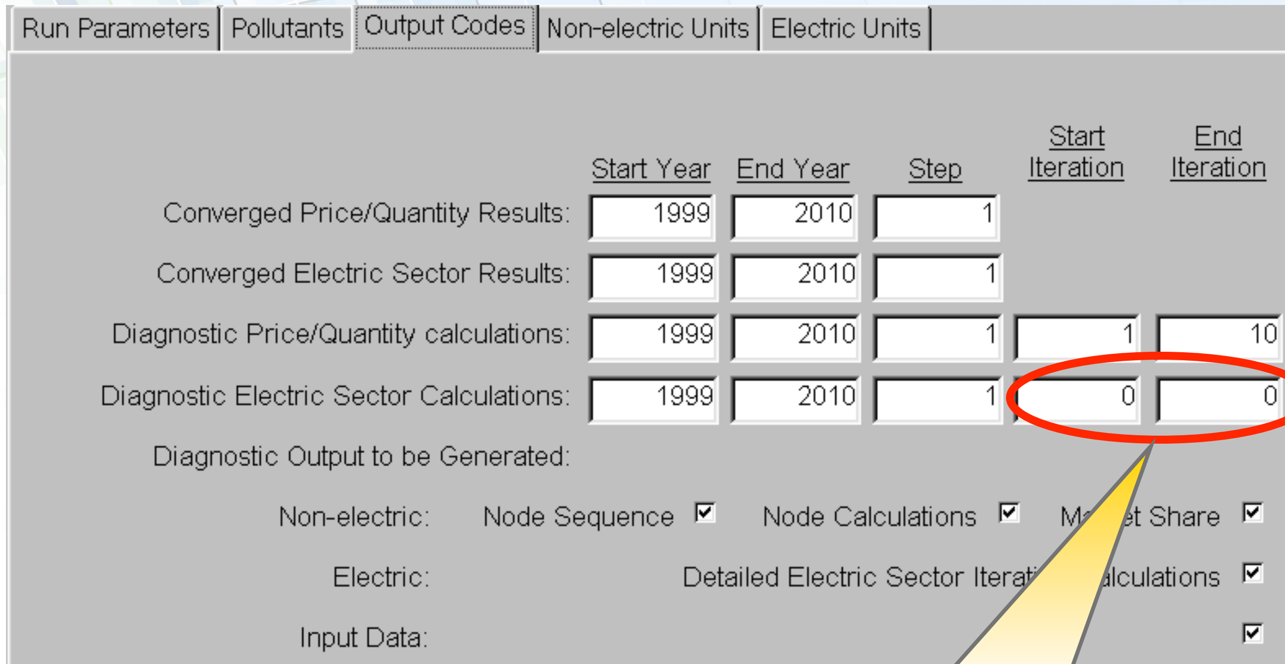
$$\frac{\$662{,}156{,}800}{15{,}182{,}986\ MWh} = 43.612\ \$/MWh = 4.3\ cents/kWh$$

Case-Level Input Data - Output Codes (Model Output Reports)

- Converged P/Q and electric sector results are the basic model output and can be generated for user-specified time steps

- Diagnostic output provides more details and is typically used for debugging

- Electric sector report includes
  - Input data
  - Load curve
  - Loading order
  - Unit-level generation
  - Fuel consumption



Set the two values to 0 to get only the converged iteration results

Summary

- The electricity representation in BALANCE is a simplification -- it should not be used to simulate only the electric sector -- the entire energy system should be simulated
- The strength of BALANCE is that the electric sector directly interacts with fuel suppliers and energy consumers
- There are three different methods for representing the electric sector in BALANCE; they are often combined

Electric Sector Cases - Input Data

- Case 1: Base Case (import Electric Case from the course CD)

- Case 2: Repower old and inefficient coal unit COAL1 with new AFBC unit
  - Repower in the year: 2005
  - New heat rate: 9,800 btu/kWh
  - New unplanned outages: 0.15
  - New planned outages: 35 days
  - New capital cost: 600 $/kW
  - New life expectancy: 20 years

- Case 3: Advanced technology: Introduce Nuclear
  - Nuclear on-line year is 2007

- Case 4: Renewable technologies (dispatchable and non-dispatchable)
  - Geothermal on-line year is 2005
  - Wind becomes available in 2004
  - Solar becomes available in 2004

Electric Sector Cases - Input Data

- Wind and solar development plan for Case 4:

Capacity installed	Wind Farm Units #	Wind MW	Wind kboe-energy	Solar Units #	Solar MW	Solar kboe-energy
2004	1	50	72.05	1	5	5.50
2006	3	150	216.15	3	15	16.50
2008	6	300	432.30	6	30	33.00
2010	9	450	648.45	10	50	55.00
2012	12	600	864.60	15	75	82.50
2014	15	750	1080.75	21	105	115.50

- **Examine and compare all cases to the BASE CASE**
  - **Electricity price over time**
  - **Change in fuel consumption level and fuel mix over time**
  - **Electricity generation by different plant types**