ORNL/TM-2009/102

Power Transfer Potential to the Southeast in Response to a Renewable Portfolio Standard: Interim Report 2

May 2009

Prepared by
Stanton W. Hadley – ORNL
Thomas Key – EPRI
Rajat Deb – LCG Consulting

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May 2009

OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
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Abstract

Electricity consumption in the Southeastern US, not including Florida, is approximately 24% of the total US. The availability of renewable resources for electricity production is relatively small compared to the high consumption. Therefore meeting a national renewable portfolio standard (RPS) is particularly challenging in this region. Neighboring regions, particularly to the west, have significant wind resources and given sufficient long distant transmission these resources could serve energy markets in the SE. This report looks at renewable resource supply relative to demands and the potential for power transfer into the SE. It shows that development of wind resources will depend not only on available transmission capacity but also on electricity supply and demand factors.

1. Introduction – SE needed renewables under RPS

Current discussions about increasing the amount of renewable energy in the U.S. center on the creation of a Renewable Portfolio Standard (RPS). Each utility would be required to provide an increasing fraction of their total production from qualified renewable resources. A key concern is that the Southeastern U.S. does not have as many cost-effective resources available. Utilities there may need to import significant quantities of renewable energy from other regions of the country, most likely wind power from the Midwestern states. Other options may be available too, such higher-cost local generation, purchase of renewable energy credits without the physical transmission of power, or payment of an alternative compliance payment to the U.S. Treasury.

Under the recently proposed RPS from Sen. Bingaman, "each utility that sells electricity to electric consumers shall obtain a percentage of the base quantity of electricity the electric utility sells to electric consumers in any calendar year from new renewable energy, existing renewable energy, or energy efficiency." The percentage ramps up from 4% in 2011 to 20% by 2021 and thereafter. The utility will utilize renewable energy credits, energy efficiency credits (not more than 25% of total) and/or payments of 3¢/kWh (adjusted for inflation). Tradeable credits will be issued to new renewable production, but existing renewable energy will receive non-tradable credits. Existing hydroelectric power and municipal solid waste facilities are not included in either the numerator or denominator when calculating the percentage of generation from renewable power.

Other bills have been proposed and any final law will likely be different from all of the current proposals. For example, the Waxman-Markey bill sets the standard at 17.5% in 2020, with a long-term goal of 25% from 2025 to 2039. As a consequence of these variations, this paper will evaluate the potential impact on the Southeast of a 15% RPS by 2020; any higher amount will simply amplify the impacts. We will also show some results from a 20% RPS in order to show the differential involved with higher RPS targets. A recent study from NREL compares the requirements and effects of three recently proposed bills: the Bingaman, Markey, and Waxman-Markey (Sullivan, et al. 2009).

The regions used for this analysis (Figure 1) are those defined in the Energy Information Administration (EIA) NEMS model (DOE 2008). These regions are based on the North American Electric Reliability Council (NERC) regions from 2004 and have not been adjusted yet to reflect several changes in regional boundaries, most notably the addition of Gateway (eastern Missouri and southern Illinois) and most of Kentucky to SERC. For consistency with the EIA data and reporting, the models used in this study, EPRI NESSIE model and LCG's UPLAN model, also use these regions in their analysis of the electric power sector.

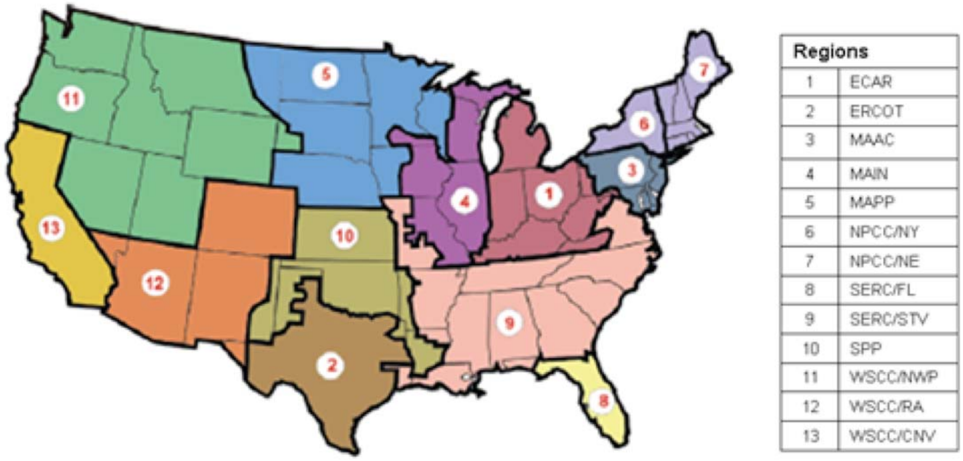


Figure 1. Thirteen NERC Regions used in NEMS, NESSIE, and UPLAN Models.

Using the demands from the latest EIA Annual Energy Outlook 2009 Reference Case (post-Stimulus Bill), the expected sales of electric power (Net Energy for Load) in the Southeast (SERC and FRCC) are shown in Table 1. With a 15% RPS, 186 TWh would need to be produced or delivered to the Southeast while a 20% RPS would require 248 TWh in 2020. Because of the variety of definitions of “renewable” the actual amount needed may be different. For example, the Bingaman bill does not include existing hydropower and municipal solid waste. When excluding these sources, the total amount of renewables needed in the 15% RPS drops from 186 TWh to 180 TWh. However, since these two technologies provide 39 TWh in 2020 (in the AEO2009 Reference scenario) the amount of other renewables required is higher than if they are included. See this project’s Task 1 interim report (Hadley and Key 2009) for more details.

Table 1. 2020 Southeast electricity loads (TWh)

	SERC	FRCC	Total SE
Net Energy for Load	970	270	1240
15% of NEL	145	40	186
20% of NEL	194	54	248

2. Available renewable resources in the Southeast

The Southeast has a number of renewable resources that can be used to meet a RPS. However, the total amount economically available is likely less than 15% of total generation. Several studies have been done that look at renewable energy resources in all or part of the southeast. The key studies used for the amounts described below are:

- *Annual Energy Outlook 2009* by the Energy Information Administration, March 2009
- *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* by EIA, March 2008
- *Yes We Can: Southern Solutions for a National Renewable Energy Standard*, Southern Alliance for Clean Energy Feb. 2009
- EPRI analysis of Wind capacities Feb. 2009 (?)
- *A Geographic Perspective on the Current Biomass Resource Availability in the United States*, NREL/TP-560-39181, National Renewable Energy Laboratory, December 2005.
- *Rooftop Photovoltaics Market Penetration Scenarios*, NREL/SR-581-42306, NREL, Feb. 2008.
- *Florida Renewable Energy Potential Assessment*, Navigant Consulting, Dec. 2008.
- *Eastern Interconnection Wind Integration & Transmission Study (Draft)*, NREL, Midwest ISO, and Enernex, 2009.

A separate study is underway at ORNL funded by the Energy Foundation that will conduct a more thorough literature review of the amounts of each renewable energy category that is potentially available in the SE.

2.1 Wind

Onshore wind capabilities in the Southeast are relatively modest. Less than 20 TWh of power could potentially be generated in the SE states (Table 2) using data from EPRI. The table shows the amounts if capacity factors for wind turbines vary between 18% and 37% depending on the class of wind. The wind resource estimates for in states that have some territory in other reliability regions have been downscaled to reflect the amounts within the SERC and FRCC borders. Note that half of the potential production in SERC comes from Missouri, with its northwestern portion having the best quality of wind potential. This region is still rather distant from the rest of the SERC region and load centers.

Table 2. Potential Onshore Wind Capacity in SERC region by state (EPRI)

	AL	AR	FL	GA	LA	MO	MS	NC	SC	TN	VA	Total
Potential Capacity (GW)	0	0.3	0	0	0	6.0	0	1.9	0.3	1.1	1.8	11.4
Expected prod. (TWh)	0.0	0.5	0.0	0.0	0.0	9.6	0.0	3.5	0.5	2.1	3.3	19

Additionally, offshore wind capacity is potentially available. However, this form of wind energy has not yet been tapped within the US. It is beginning to be developed in Northern Europe, in the North Sea and in the Atlantic off the coast of Ireland and England. The EWITS study developed estimates of wind capacity along the Atlantic coast. These were largely along the Virginia and North Carolina coasts, as shown in Figure 2. The total amount in the SERC region was 4,000

MW, even in the aggressive penetration scenario. At a capacity factor of 40%, this totals to 14 TWh per year.

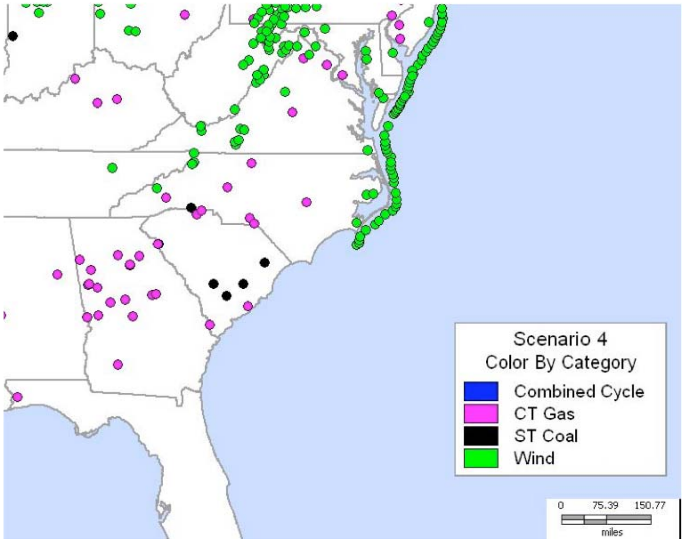


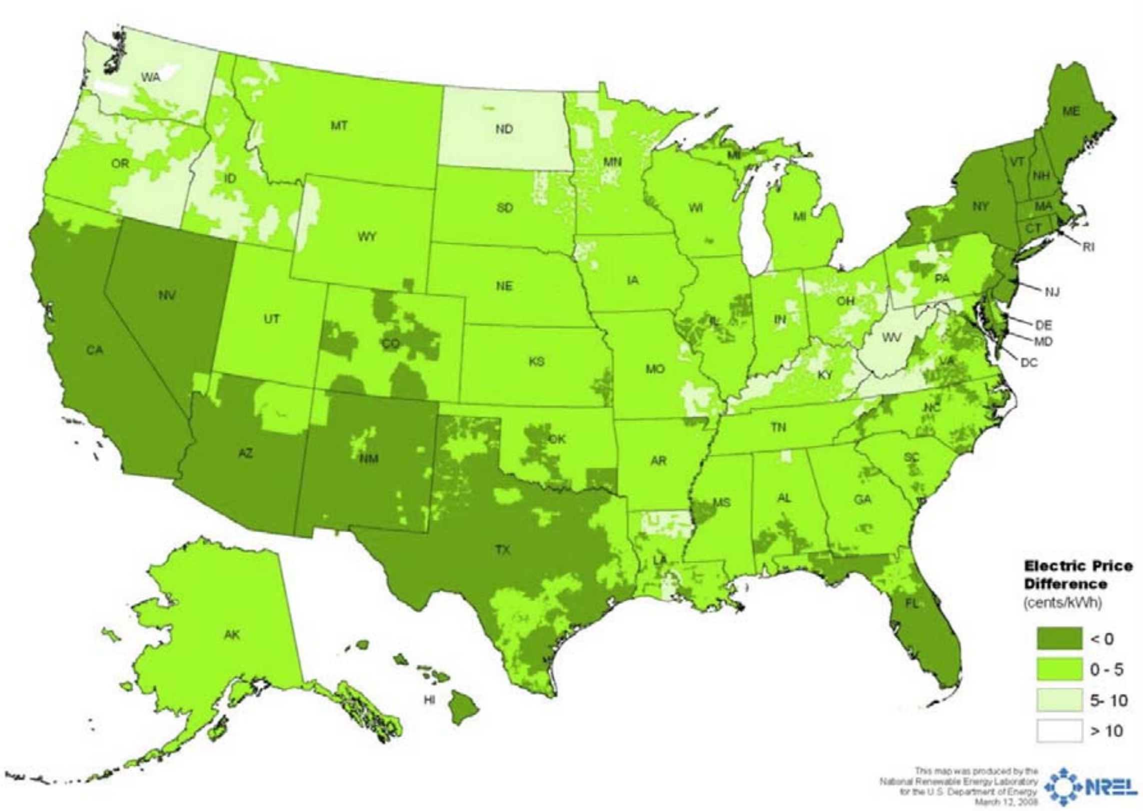
Figure 2. Locations of Southeast Offshore Wind in EWITS study

Combined, the total amount of potential wind capacity for the southeast is roughly 15 GW, with a production amount of 33 TWh. This includes a speculative 4 GW of offshore wind plus 6 GW in upstate Missouri.

Separately, Navigant Consulting performed an analysis of renewable energy potential in the state of Florida (Navigant 2008). Their analysis projected 67 MW of onshore wind and 105 MW of offshore wind by 2020 in the most favorable circumstances. These contribute 0.5 TWh of generation to the region.

2.2 Solar

Solar capacity could be extensive in the southeast, depending on the cost of deployment. One study of rooftop PV potential from NREL shows much of Florida (and small parts of the rest of the Southeast) with solar prices below residential electricity prices in 2015 (Figure 3) (Paidipati et al. 2008). The technical potential (regardless of cost) is on the order of 200 GW, but actual deployment will be much smaller.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Electric Price Difference
(cents/kWh)
< 0
0 - 5
5- 10
> 10
This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy March 12, 2008
NREL

Figure 3. Price difference between solar PV levelized costs and residential electricity in 2015 with a 13% increase in residential prices and no incentives (Paidipati et al. 2008)

The authors of the study made state-by-state analyses of existing policies and the effect of potential changes to policies. Under their Business as Usual scenario, they projected cumulative installations of rooftop PV for the southeast at 213 MW. Under their best-case assumptions, they forecasted almost 1,000 MW (Table 3). Assuming a 25% capacity factor, this works out to around 2 TWh, much less than the required 186 TWh identified in Table 1. In their analysis, they proposed various policies to encourage further solar development, most of which North Carolina already has planned (note that the amount is the same for both the BAU and best case scenarios.)

Table 3. Southeast states' cumulative rooftop PV capacity (MW) in 2015 under BAU and best case scenarios (Paidipati et al. 2008)

State	Business as Usual	Best Case
Alabama	1	87
Arkansas	1	1
Florida	30	330
Georgia	11	41
Louisiana	1	34
Mississippi	2	92
North Carolina	154	154
South Carolina	3	43
Tennessee	6	84
Virginia	3	62
West Virginia	1	8
Total	213	936

A separate study by Navigant of the potential for renewable energy in Florida included an analysis of the potential for ground-mounted PV in the state. They projected a technical potential of 37 GW in 2020, representing 600 square miles or ~1% of the state's area. Depending on the renewable energy policies (including renewable energy credits) they projected between 0 and 9.5 GW of ground-mounted PV by 2020 (producing up to 21.6 TWh), roughly one fourth of the technical potential. The Southern Alliance for Clean Energy extrapolated these results to the eleven states of the southeast and came up with a total technical potential of 346 GW and feasible capacity of 74 GW. The feasible generation was 160 TWh, assuming favorable renewable energy policies and RECs. With the higher price differential for solar in the rest of the southeast (Figure 3) it is less likely that this solar amount could be feasible by 2020.

2.3 Biomass

Biomass generation may be the largest supply of renewable production in the southeast. According to the NREL report *A Geographic Perspective on the Current Biomass Resource Availability in the United States* (Milbrandt 2005*)* the total potential biomass resources available in the southeast is around 120 million metric tonnes per year. Assuming 16 mmbtu/tonne and a heat rate of 10,000 btu/kWh (34% efficiency) the total potential electricity from these resources is 145 TWh, a significant fraction of the required 186 TWh identified in Table 1. With a capacity factor of 70%, this translates into a total potential electric capacity of around 24 GW. However, even if this total potential were utilized, some portion of it would be used for liquid biofuels rather than electricity production. As such, it would not qualify for the renewable portfolio standard, which only applies to electricity production. Figure 4 shows the split of resources by type of fuel.

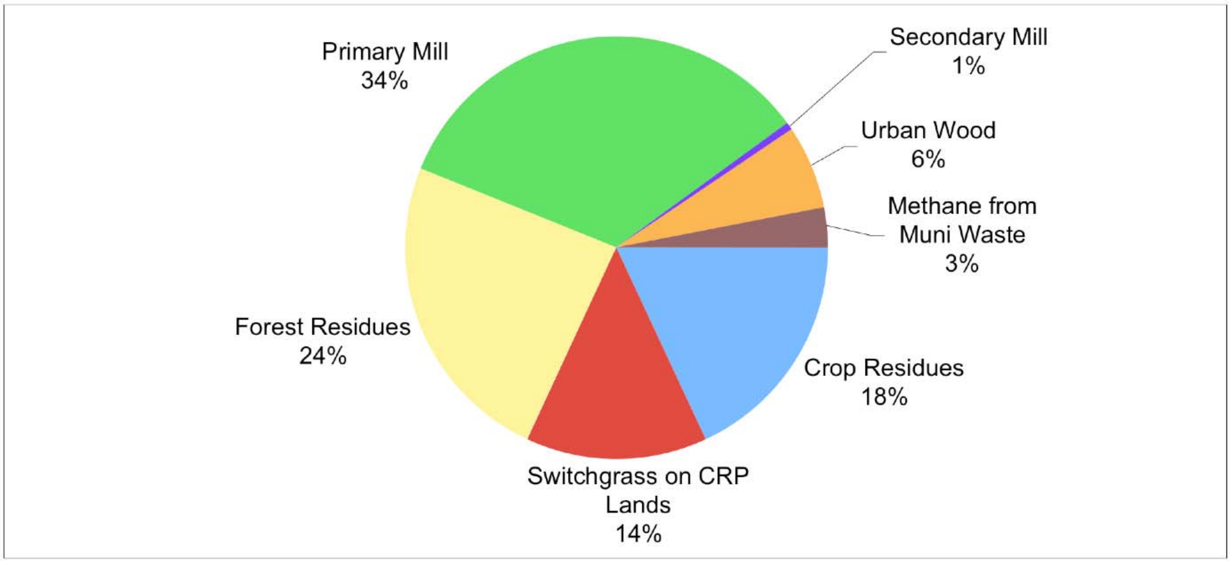


Figure 4. Total potential biomass resources in the southeast by type (Milbrandt 2005)

The AEO2009 projects 12 TWh of wood and other biomass production in 2020 in the southeast. Much of this generation is from cofiring in a coal-fired power plant, rather than as dedicated biomass capacity. In addition, it lists another 3 TWh from biogenic municipal waste, but this does not qualify for the RPS according to Bingaman's proposed bill. The analysis by EIA of Senate bill 2191 (the Lieberman-Warner Climate Security Act) placed biomass generation in the southeast at 55 TWh by 2020, while an analysis of the RPS within the American Clean Energy and Security Act of 2009 reported 34 TWh of production.

2.4 Hydro

Hydroelectricity is currently the most widely used renewable resource within the southeast. The resources have been developed by the TVA, the US Army Corps of Engineers, and other utilities mainly in the central part of the southeast (Figure 5). Total resources in the SERC and FRCC region are between 12 GW and 13 GW with a typical production of 35 TWh. (Wet and dry years, such as the drought in 2006 and 2007, will cause hydropower output to vary by as much as 50%.) Most major resources have been developed although some additional incremental generation may be realized by upgrading existing hydro turbines and improving operating efficiency at existing facilities. Nameplate capacity in SERC rose from 12.3 GW in 2004 to 12.7 GW in 2007.

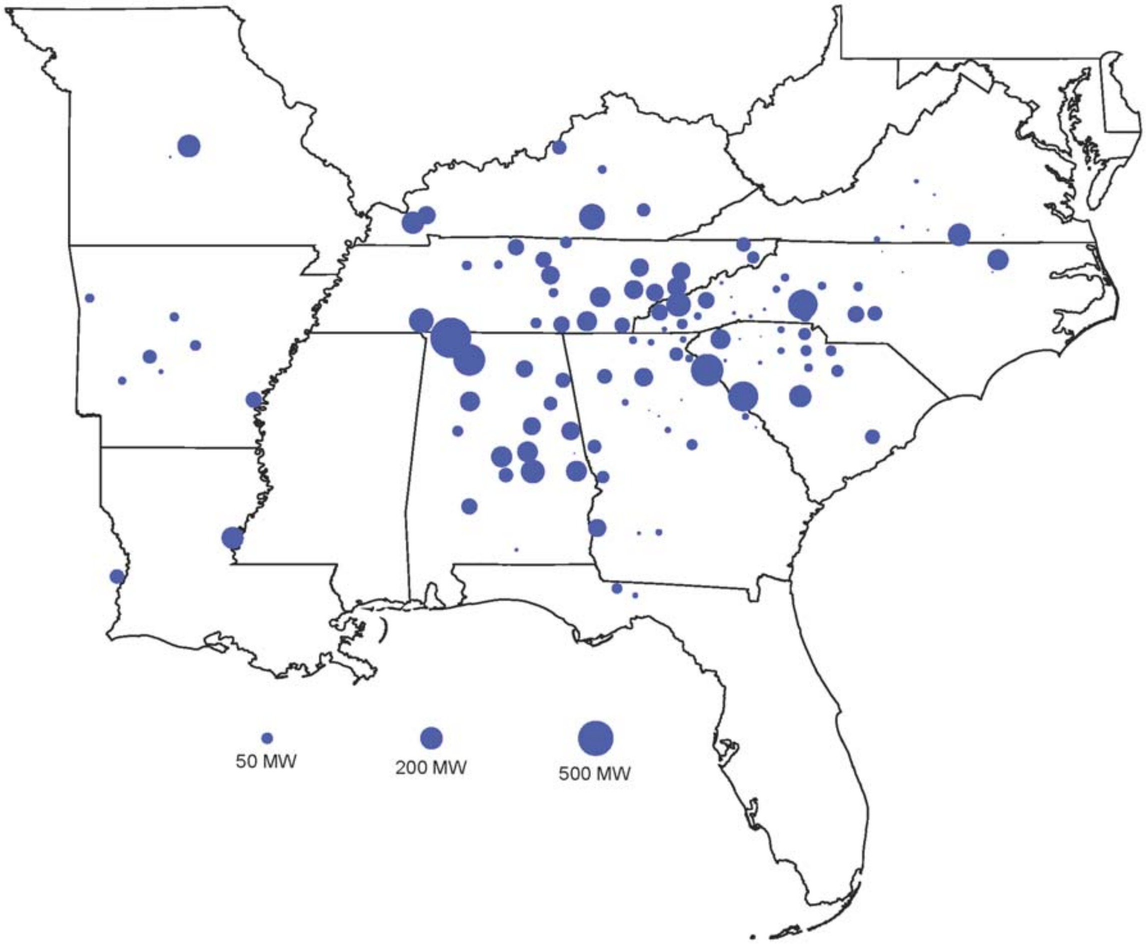


Figure 5. Location of Hydroelectric facilities in the Southeast (EPA 2008)

In many RPS proposals, including the Bingaman proposal described above, existing hydropower does not count towards meeting the standard, but is also removed from the total generation to which the percentage is applied.

Another new technology with potential is hydrokinetic machines that operate in free-flowing rivers or ocean currents. Tidal and wave power equipment are also under research. However, these technologies are currently only at the developmental or pilot-scale level and are unlikely to provide a significant portion of the needs under an RPS.

EPRI has identified a nationwide potential for hydro capacity gains of 3.7 GW by 2015 and 23 GW by 2025, with a total potential of 85 – 95 GW (EPRI 2007). However, they provide no geographic breakdown of this amount. Some 10 GW of this potential is at existing facilities or small hydro and so may be applicable to southeastern rivers and dams (Table 4). Between this new capacity and increased efficiency at existing dams, they project a potential nationwide generation of 40-50 TWh from conventional hydro. The southeast would only capture a fraction of that. Hydrokinetic capabilities are largely from tidal in-stream operations, which are not being pursued currently in the southeast but rather in the Pacific Northwest, Hawaii, and New York.

Table 4. Estimated National Waterpower Capacity Gains (MW) by 2025 (*Source EPRI 2007*)

Waterpower Technology	2006	Potential	By 2010	By 2015	By 2025
Conventional hydropower					
Large Hydro (>30 MW)	66,536		0	0	0
Capacity gains at existing large and small hydro	~100	4,300	375	1,000	2,300
New small hydro (>1 MW <30)	8,023	36,000	25	500	2,000
New low power hydro <1 MW	313	22,000	100	350	700
New hydro at existing dams	–		25	500	5,000
Conventional hydro potential realized			525	2,350	10,000
Hydrokinetic					
Tidal instream	Demos	300	115	300	3,000
Instream and constructed waterways	–	12,500	0	30	?
Hydrokinetic potential realized			115	330	3,000
Ocean energy (wave)	Demos	10,000 - 20,000	84	1,000	10,000
TOTAL	**74,972**	**85,100 - 95,100**	**724**	**3,680**	**23,000**

2.5 Amount deployed under different scenarios

Under the newest Annual Energy Outlook 2009 Reference scenario (released in April and including the impact of the recent stimulus funds), only 18 GW of renewables are used in the southeast, generating 68 TWh (Table 5). Of this amount, only 29 TWh of generation is from qualified renewables; the remainder is from hydroelectric and municipal waste. It does include 3.6 GW of wind (3.57 GW in Florida onshore and the 30 MW existing in Tennessee). The biomass generation amount of 19 TWh includes both dedicated biomass plants (1.4 GW) plus cofiring in some of the region’s coal-fired plants.

Table 5. Southeast 2020 electricity capacity, generation and load from AEO2009 post-stimulus (EIA 2009)

	Capacity (GW)	Generation (TWh)
Coal	149.7	572
Oil & Gas	232.5	188
Nuclear	38.7	334
Pumped Storage/Other	7.7	-1
Conventional Hydropower	12.2	35
Geothermal	0.0	0
Biogenic Municipal Waste	0.8	4
Wood and Other Biomass	1.4	19
Solar Thermal	0.0	0
Solar Photovoltaic	0.0	0
Wind	3.6	11
Offshore Wind	0.0	0
less gen for own use		-10
Electric Gen for Customers	285.4	1152
Net imports from other regions		77
Purchase from CHP		12
Net Energy for Load		1240

The amounts in this scenario expand the amount of renewables when compared to earlier reference cases due to the policies in the American Reinvestment and Recovery Act. Other recent NEMS scenarios by EIA had even more development. The analysis by EIA of the renewable energy standard within the proposed American Clean Energy and Security Act of 2009 (EIA 2009) placed qualified renewable generation in the southeast at 44 TWh by 2020 (Table 6). Biomass production increased from 19 TWh to 34 TWh; other renewables essentially stayed the same. Even this scenario has only a fourth of what is needed for the region to supply its own share of a 15% RPS requirement.

Table 6. Southeast electricity capacity, generation and load from EIA evaluation of RPS policy in American Clean Energy and Security Act (*Source EIA2009b)*

	Capacity (GW)	Generation (TWh)
Coal	148.9	558
Oil & Gas	230.2	184
Nuclear	38.7	334
Pumped Storage/Other	7.7	-1
Conventional Hydropower	12.2	35
Geothermal	0.0	0
Biogenic Municipal Waste	0.8	4
Wood and Other Biomass	1.6	34
Solar Thermal	0.0	0
Solar Photovoltaic	0.0	0
Wind	3.6	11
Offshore Wind	0.0	0
less gen for own use		-10
Electric Gen for Customers	284.1	1149
Net imports from other regions		79
Purchase from CHP		12
Net Energy for Load		1240

A recently released study by NREL on RPS proposals (Sullivan 2009) includes a table that shows the state-by-state generation by different renewable technologies (Table 7). The analysis was done using their REeDS model and the data shown in the table is the sum for the eleven states in the southeast (as opposed to the SERC and FRCC regions). The data represents their modeling of the Markey's bill H.R. 890, the American Renewable Energy Act for the year 2030. Even though this bill required the most renewable generation of the three studied, 25% by 2025, the southeast states did not generate the required amounts. Instead, they were expected to import renewable power and/or purchase renewable energy credits from states with surpluses.

Table 7. Southeastern renewable generation in 2030 under Markey Bill (TWh) (*Source Sullivan 2009*)

	Wind	Solar	Bio	Total
Alabama	0	0	1.4	1.4
Arkansas	0.4	0	0.7	1.1
Florida	2.9	3.2	11	17.1
Georgia	2.1	0	1.6	3.7
Louisiana	3.9	2.8	0.7	7.4
Mississippi	0	0	1.2	1.2
Missouri	13.4	0	0.8	14.2
North Carolina	10.8	7.0	7.0	24.8
South Carolina	0.4	1.5	2.2	4.1
Tennessee	1.0	0	1.5	2.5
Virginia	2.5	1.7	1.4	5.6
Total	37.4	16.2	29.5	83.1

The amounts above represent only the electricity generated by the electricity sector and does not include industrial or other sectors' generation for their own end-use. Particularly in the southeast, generation from biomass through cogeneration at paper mills provide significant quantities of electricity. These are not greatly affected by changes in plans and do not qualify for tradable renewable energy credits in some of the bills under discussion. Under the AEO2009 with stimulus package scenario by 2030 there is 37 TWh of qualified renewable resources from end-users while in the Waxman RPS the total is only 36 TWh (Table 8).

Table 8. Renewable resources in 2030 from different scenarios and models

	Markey RPS	AEO2009 with Stimulus (NEMS)			Waxman RPS (NEMS)		
	(REeDS)	Elec Sector	EndUse	Total	Elec Sector	EndUse	Total
Wind	37	11	0	11	11	0	11
Solar	16	0	5	5	0	7	7
Biomass	30	18	32	50	129	28	157
Total	83	29	37	66	139	36	175

Another point to be made from this table is that different models and associated assumptions can give large differences in the amount and type of generation developed. The REeDS model analysis of the Markey RPS develops a large amount of solar and wind resources while the NEMS analysis supply most renewable generation in the southeast from biomass.

2.6 Gap in generation needed

So how much of a gap is there between what is needed to satisfy an RPS of 15% and the possible sources within the southeast? Table 9 lists the amounts of supplies potentially available within the region, based on the statements from sources listed above. None of the sources by themselves can meet the requirements. Solar comes closest, but these values are based on a very rough extrapolation of technical potential for the region based on the Florida study. It does not take into account the time it would take to construct such sources, nor does it consider the cost to provide that level of demand. Biomass has the next largest potential, but again, the amount is based on the maximum utilization of all resources without regard to construction time or economic cost. It also does not consider that some of the biomass available will be used for liquid fuels.

Table 9. Southeast RPS Requirement and Potential Supplies (2020)

Generation Needed in 2020	**186 – 248 TWh (15% to 20% RPS)**
Wind Resources	19 TWh generated within SERC (EPRI) 6.7 TWh Onshore + 14 TWh Offshore (EWITS) 7 – 11 TWh (EIA)
Solar	2 TWh generation by 2015 Rooftop potential (NREL) 0 – 160 TWh ground-mount potential depending on policies (SACE and Navigant)
Biomass	145 TWh technical potential biomass generation (Calculated from NREL supply estimates) 19 – 55 TWh generated in 2020 depending on policies (EIA) 46 TWh generated by 2020 in SERC with CO_2 policy (EPRI)
New Hydro (incremental)	40 – 50 TWh generation nationally (SERC amount unknown) (EPRI)
Gap in Supplies	**From 174 TWh needed to less than zero depending on solar and biomass deployment**

When considering how much wind from other regions will be needed to meet the renewable portfolio standard in the southeast, it becomes clear that without massive investment in biomass and solar technologies, imported wind is the best choice. To bring in this wind large amounts of transmission will be needed. It then becomes a question of how much the solar and biomass can realistically be deployed in the next 11 years. While biomass generation has an established base in the region, a scale-up from the current projection of 12 TWh will require the construction of new plants, conversion of many existing fossil plants, and an established biomass fuel production infrastructure. Solar production has not been developed in the southeast yet, so expansion to cover ~1% of the land area of the southeast would be highly unlikely.

Further analysis of the other renewables resources (comparative cost, supplies, policies required) is beyond the scope of this study.

3. Planned transmission resources in Southeast

As part of the analysis to understand the transmission issues related to transporting energy with SERC and for importing wind energy into the Southeast, EPRI contracted LCG Consultants to conduct a study using their UPLAN production simulation and transmission model. Available and planned transmission additions are based on several recent studies. The total inter-regional transmission capacity requirement, which is not currently in the plan, was assumed at a level for transporting renewable energy to achieve 15% RPS in 2020. This chapter presents an overview of results related to transmission resources combining the UPLAN model approach and other available results on the eastern interconnection. Appendix A is a description of the UPLAN model.

3.1 Introduction (UPLAN model)

LCG Consulting has provided input to EPRI and ORNL to determine regional energy trading potential between SERC and adjacent regions under different RPS scenarios. In particular, LCG is to project how much renewable energy, especially wind power, can be transported to SERC from other areas in the Eastern Interconnection. LCG will be looking at the RPS in each region in 2020 and determine how much additional renewable capacity can be added to compensate for any shortage of the RPS requirements in SERC.

LCG applied there existing database for Eastern Interconnection for 2009 including all the generators and major inter-ties between the regions. This 2009 Eastern Interconnection database represents 7,159 generators and 131 transmission inter-ties. UPLAN was applied to simulate unit commitment and dispatch for the selected year to provide a preliminary estimate of transfers between the control areas, especially to SERC from all other areas.

LCG’s Network Power Model (UPLAN) is an integrated electricity generation and transmission model developed to simulate both the behavior of market participants and the physical features of the electricity system. It projects detailed physical and financial operations of electricity markets conditions ranging from traditional regulation to today’s post-restructuring competitive market structures. The model provides the consistent, structured framework, as well as the detailed quantitative inputs and results, required to evaluate the full implications of different fundamental drivers and market participant decisions.

UPLAN is a full network model designed for electricity market simulation, replicating the engineering protocols and market procedures of an operator, and captures the commercial activities, such as bidding, trading, hedging, and contracting, of all players in a restructured power market. The model performs coordinated marginal (opportunity) cost-based energy and ancillary service procurement, congestion management, full-fledged contingency analysis with Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).

UPLAN dispatch algorithm is capable of simulating all different types of generators such as thermal, hydro, wind and renewable, cogeneration and many other technologies. UPLAN can represent almost any kind of generation, transmission and a combination of loads. UPLAN has been used extensively to simulate and analyze such regional markets as PJM, New York, New England, MISO, ERCOT and California.

3.2 The Eastern Interconnection Database, 2009

For this demonstrative analysis, LCG has developed a DC model for the Eastern Interconnection including New York, New England, PJM, MISO, SPP and SERC in the U.S. and Quebec, Ontario, New Brunswick, and Nova Scotia in Canada. For this version they made a reduced interconnection to FRCC. Each control area is represented and connected by inter-ties. The inter-ties represent the transmission system and carry electricity between the control areas. The intra-control area transmission lines are ignored because they do not contribute to the transfer of electricity between areas. The model includes all the generators and hourly loads of all the control areas in the regions mentioned. The Eastern Interconnect Model simulates the flows from and to neighboring areas and provides imports/exports and comparative price performance of a zone.

There has been considerable generation development in SERC since 1998. However, much of this generation has not contracted to serve load. According to the latest SERC survey, as of December 31, 2007, total generation (including uncommitted generation) connected to the transmission system in SERC was 266,622 MW, with an additional 2,314 MW of net projected additions planned to be connected by July 1, 2008. Over the period covered by the 2008 survey, generation capacity additions totaled 49,647 MW (Figure 6).

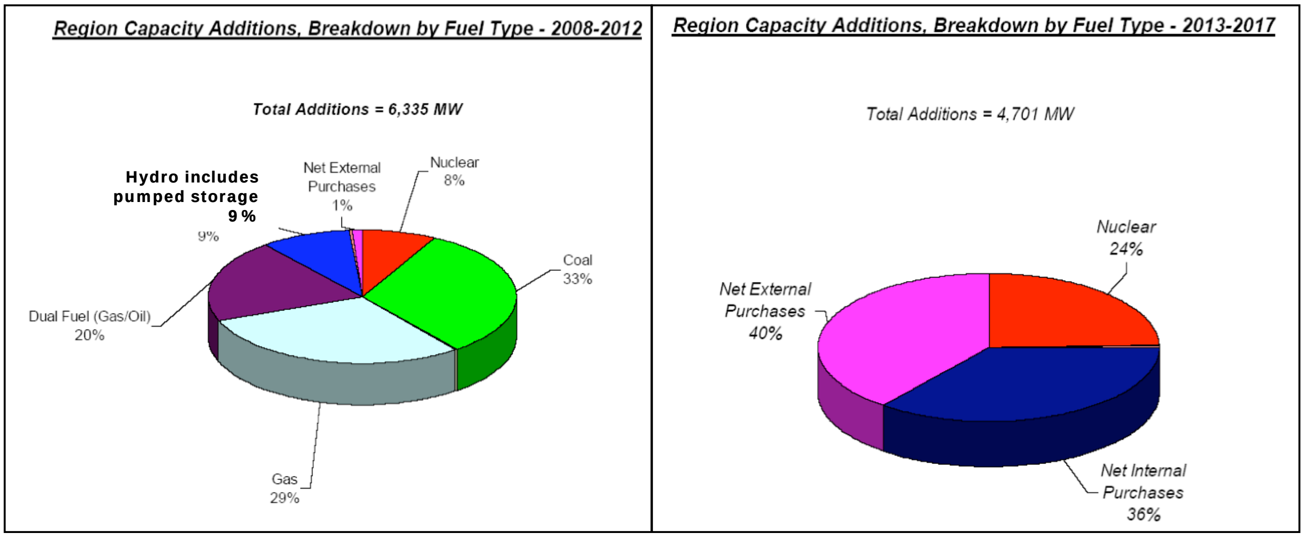
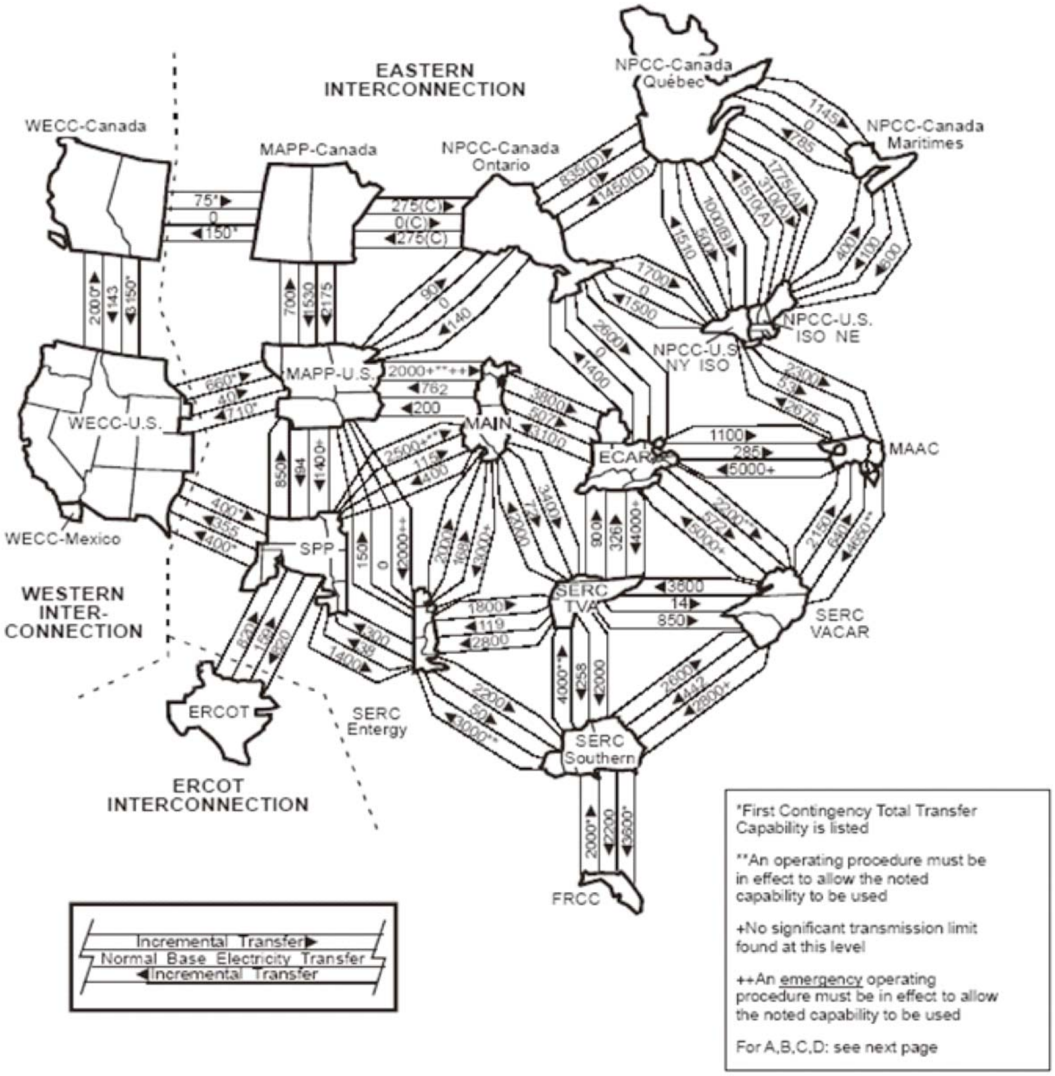


Figure 6. SERC Generation Development (*Source: SERC Reliability Corporation Information Summary, July 2008)*

In developing the transmission network, LCG makes reference to several sources including, for instance, the transfer limits assumed for 2007 to 2009 period in a study conducted by NPCC CP-8 Working Group in 2007 as well as the non-simultaneous transfer capabilities from NERC 2004 Summer Assessment. Figure 7 illustrates the ability of the transmission network to transfer electricity from one area to another for a single demand and generation pattern. Different patterns of demand and generation cause variations in transfer capabilities on a day-to-day (or hour-to-hour) basis.


EASTERN INTERCONNECTION
WESTERN INTER-CONNECTION
ERCOT INTERCONNECTION
WECC-Canada
MAPP-Canada
NPCC-Canada Ontario
NPCC-Canada Québec
NPCC-Canada Maritimes
NPCC-U.S. ISO NE
NPCC-U.S. NY ISO
WECC-U.S.
WECC-Mexico
MAPP-U.S.
MAIN
ECAR
MAAC
SPP
ERCOT
SERC TVA
SERC VACAR
SERC Entergy
SERC Southern
FRCC
75*
0
150*
275(C)
0(C)
275(C)
2000*
143
150*
700
1530
175
660*
40
710*
2000+**++
762
200
90
0
140
835(D)
0
1450(D)
1145
0
785
1275(A)
310(A)
1510(A)
1000(B)
50
1510
400
100
600
1700
0
1500
2600
0
1400
2300
53
2675
3800
507
1100
1100
285
5000+
2500+**
115
400
850
94
1400+
150
0
2000++
2000
168
3000+
72
3400
2000
900
326
4000+
2200**
572
5000+
2150
640
4650**
3600
14
850
1800
119
2800
400*
355
400*
820
156
820
300
38
1400
2200
50
3000**
4000**
258
2000
2600
442
2800+
2000*
2200
3600*
Incremental Transfer
Normal Base Electricity Transfer
Incremental Transfer

*First Contingency Total Transfer Capability is listed

**An operating procedure must be in effect to allow the noted capability to be used

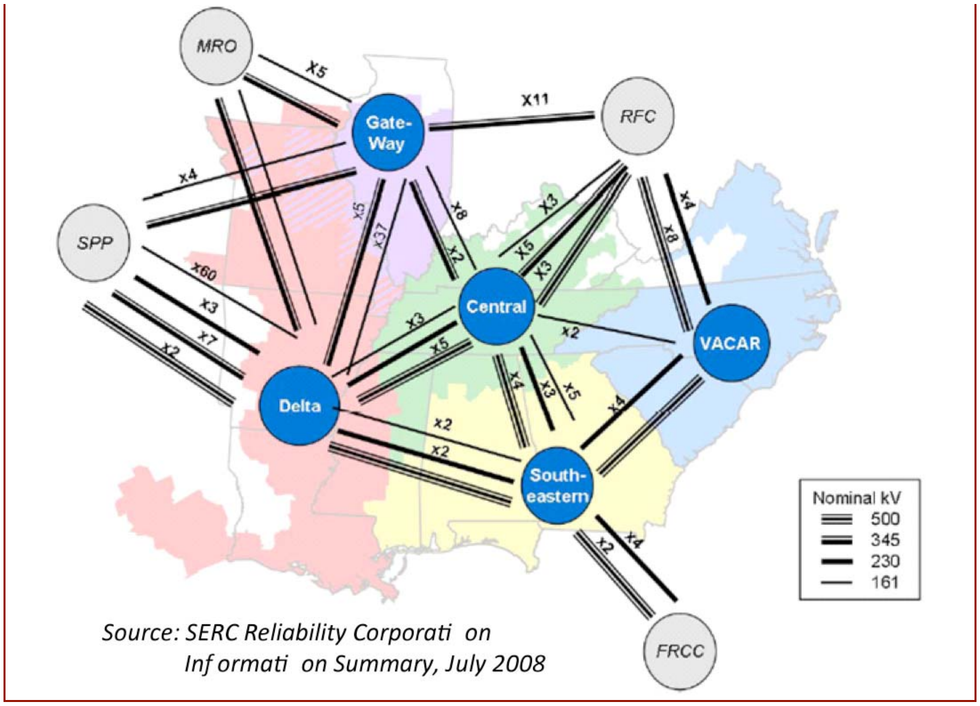
+No significant transmission limit found at this level

++An emergency operating procedure must be in effect to allow the noted capability to be used

For A,B,C,D: see next page

Figure 7. Normal Base Electricity Transfer and First Contingency Incremental Transfer Capabilities (*Source: NERC 2004 Summer Assessment)*

In addition, SERC systems have developed a robust transmission system with more than 100 transmission connections to its neighbors to the north and west. The planned transmission expansion (line additions) at 230 kV and above in SERC represents approximately 20 percent of all transmission expansion in the U.S. over the next ten years.


MRO
X5
X11
RFC
Gate-Way
x4
SPP
x5
x37
x8
x2
X3
X5
X3
x4
x8
x60
x3
x7
x2
Central
x3
x5
x2
VACAR
Delta
x4
x3
x5
x4
x2
x2
South-eastern
x2
x4
FRCC
Nominal kV
500
345
230
161

Source: SERC Reliability Corporati on Inf ormati on Summary, July 2008

Figure 8. SERC Inter- and Intra-Regional Interconnections

Table 10 is a summary of the resources and loads of the Eastern Interconnection in 2009. The peak demand and total capacity are further illustrated in Figure 9, Figure 10, and Figure 11.

Table 10. Summary of Resources and Loads in Eastern Interconnect (2009)

Region	Wind (WM)	Hydro (MW)	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Oil (MW)	Other (MW)	Total Capacity (MW)	Annual Peak Demand (MW)	Annual Energy Demand (GWh)
SERC	29	16,777	29,743	71,580	80,630	4,963	1,627	205,348	179,069	984,884
PJM	1,356	7,342	31,566	64,781	52,562	13,163	10,532	181,302	137,361	743,425
MISO	7,850	8,292	11,589	80,820	44,193	5,289	1,487	159,520	105,574	607,152
SPP	2,915	2,944	1,235	26,436	31,276	1,580	58	66,443	47,358	222,432
NEW YORK	2,008	5,838	5,263	2,837	17,452	9,072	682	43,151	34,326	168,684
NEW ENGLAND	240	3,633	4,479	2,839	17,429	5,801	1,818	36,240	27,914	136,805
TOTAL	14,398	44,826	83,874	249,291	243,542	39,868	16,204			

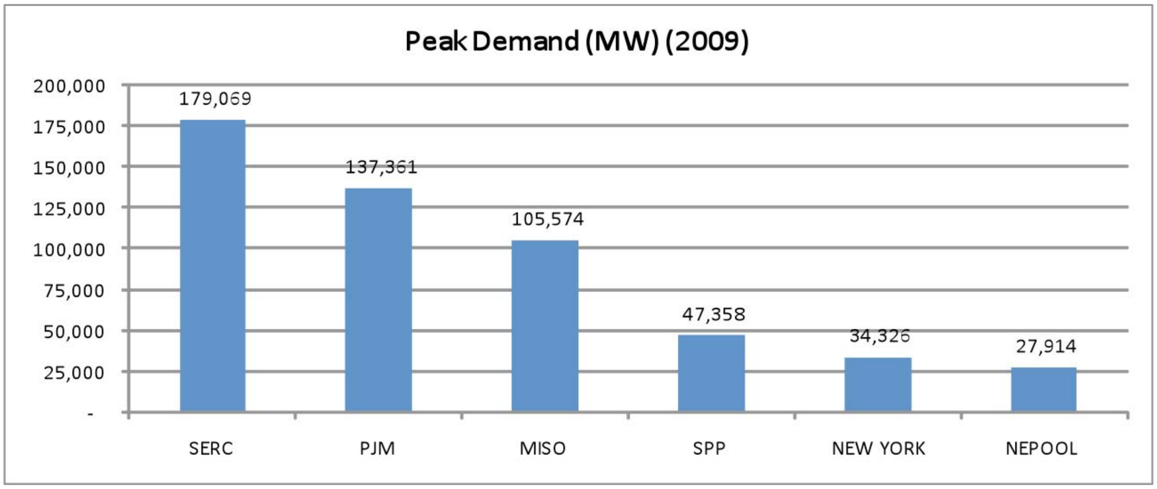


Figure 9. 2009 Peak Demand (MW) by Region

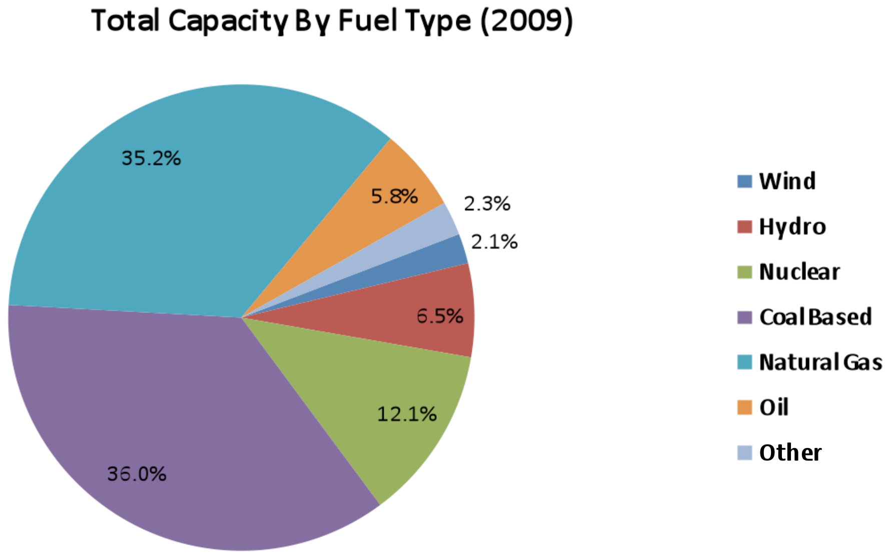


Figure 10. Breakdown of Capacity by Fuel Type in Eastern Interconnect (2009)

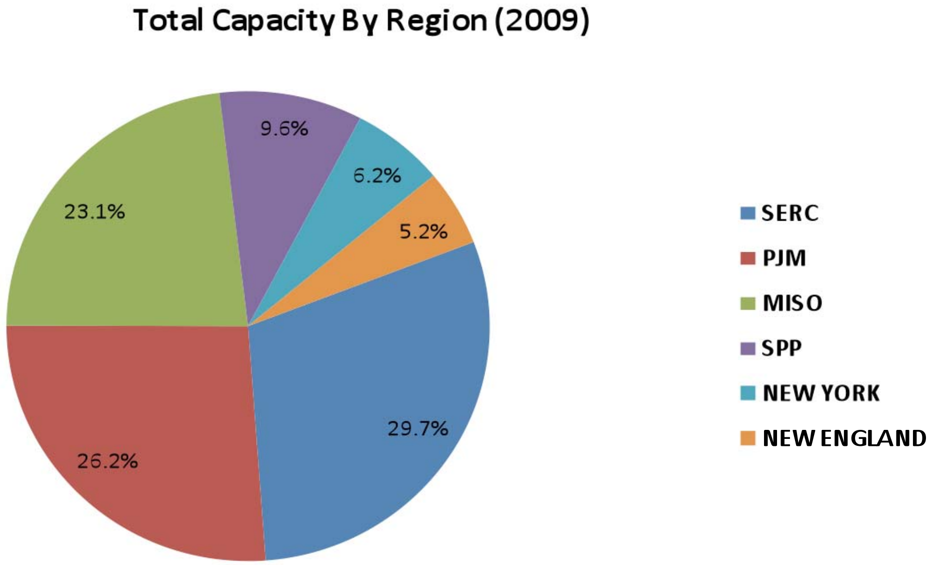


Figure 11. Breakdown of Capacity by ISO/Regions Eastern Interconnect (2009)

For this study we have developed an expansion plan to assess the available capacity for the various regions in 2020. This expansion plan takes into account generation and transmission projects that have been already approved and the proposed ones that are currently under ISO evaluation. Below is a brief description on the methodology used to develop generation and transmission expansion plans for 2020.

3.2.1 Generation Expansion Methodology

For each region/ISO, the interconnection agreements were studied carefully. The projects with interconnection status approved or under construction were selected and added in the respective zones. The units with planned retirement dates before the end of study period are not considered in the simulation.

Since the simulations were performed in order to model the RPS requirements, the majority of the capacity addition was contributed by wind generators in SPP, MISO (mostly the MAPP and some from MAIN) and PJM (ECAR and MAAC). Note that all three are quite limited. Even SPP and MISO, with significant wind resources, did not contribute very much. This is because of limited demand in these regions and lack of transmission in the current plan for exporting wind to the Southeast and Florida regions. To meet the 15% RPS by 2020, the wind generation expansion plan was designed based on regional requirements, existing wind capacity, and planned wind generation plants with signed/approved interconnection agreements.

3.2.2 Transmission Expansion Methodology

Similar to the generation expansion methodology, the proposed interconnection agreements for transmission were studied carefully for each ISO/region and the approved ones were included in the test scenarios (Table 11). The stable expansion plan was reached after running various simulation cases or scenarios on UPLAN. The results from these simulations were consistent in terms of the expected flows, prices and the reserve margins. There was no unserved energy in the system. The simulation results include renewable energy both imported into the SERC and as REC, so that the region meets RPS and federal requirements.

The network was based on 2007 series MMWG 2009 load flow case published by FERC. A transmission expansion plan was created using transmission upgrades published by MISO, PJM, NYISO, NEPOOL, and SPP which is summarized in Table 11.

Table 11. Transmission Expansion as per Interconnection agreements (2020)

Project Name	Capacity (MW)
Linden VFT Inter-Tie (New York)	300
Maple River to Alexandria SS (MISO)	2,085
Baldwin to Rush Island (MISO)	1,795
AB Brown to Gibson (Duke) (MISO)	1,430
AB Brown to Reid (BREC) (MISO)	1,430
Gardner Park (New Weston) to HWY 22 (formerly Central Wisconsin) (MISO)	1,775
Susquehanna - Roseland (PJM)	2,500
Amos - Midpoint (PJM)	6,500
Meadowbrook - Loudoun (PJM)	3,465
Calvert Cliffs - Salem (PJM)	2,810
Orrington ME and BostonMA (New England)	1,000
Maine Yankee Substation, South Boston Substation (New England)	1,000

Table 12 is a summary of the resources and loads of the Eastern Interconnection in 2020. The peak demand and total capacity are further illustrated in Figure 12, Figure 13, and Figure 14.

Table 12. Summary of Resources and Loads in Eastern Interconnect (2020)

Region	Wind (WM)	Hydro (MW)	Nuclear (MW)	Coal (MW)	Natural Gas (MW)	Oil (MW)	Other (MW)	Total Capacity (MW)	Annual Peak Demand (MW)	Annual Energy Demand (GWh)
SERC	9,742	17,860	37,072	82,012	88,985	5,026	1,627	242,324	210,097	1,167,541
PJM	44,788	7,822	34,066	65,307	54,702	13,333	10,792	230,810	158,614	865,131
MISO	40,265	8,292	11,589	84,548	52,177	5,259	1,487	203,617	122,574	713,818
SPP	11,743	2,492	1,235	19,264	31,027	1,517	58	67,336	50,741	240,018
NEW YORK	13,527	5,694	5,433	2,837	20,452	8,181	712	56,835	38,639	192,179
NEW ENGLAND	11,117	4,933	2,913	3,103	19,705	4,990	2,772	49,533	30,118	148,265
Grand Total	131,182	47,094	92,307	257,070	267,048	38,306	17,448			

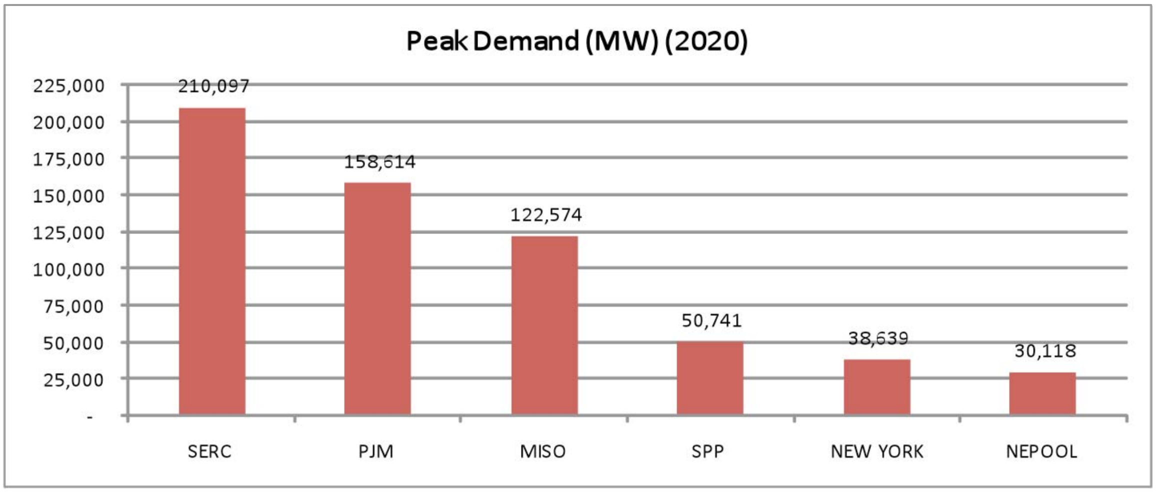


Figure 12. 2020 Peak Demand (MW) by Region

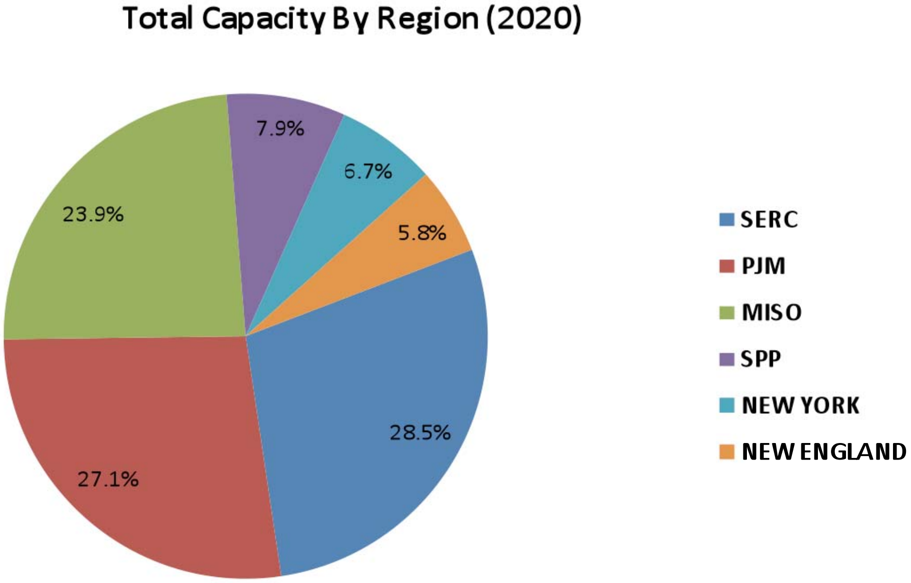


Figure 13. Total Capacity by Region (2020)

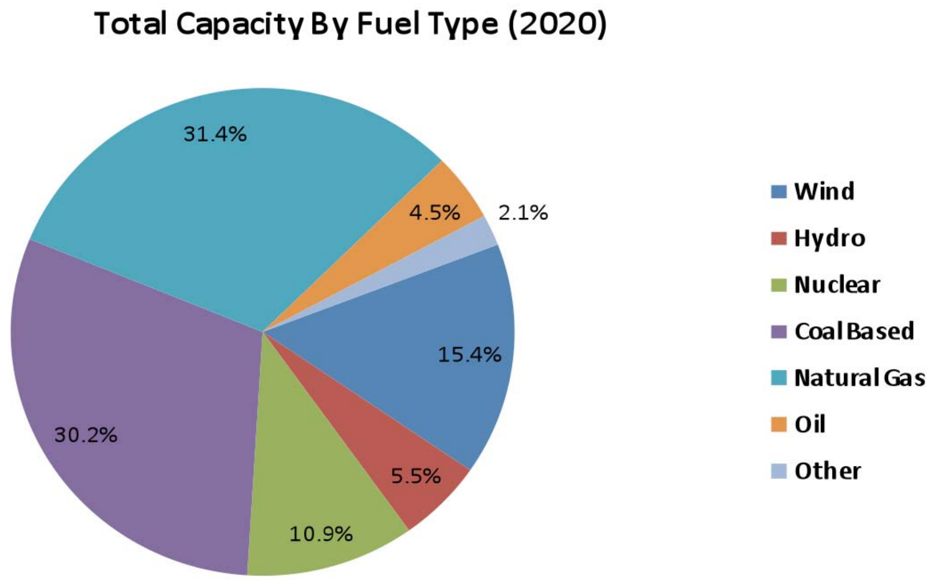


Figure 14. Total Capacity by Fuel Type in the studied Eastern Interconnection (2020)

With the total imports from MISO, PJM and SPP (Table 13), considering the transmission constraints, around 3.2% of SERC's demand and with its own renewable generation accounting up to 2.5 %, SERC can meet only about 6% of its energy requirements using renewable sources.

Table 13. Annual Zonal Flows for SERC

SERC Annual Flows (GWh) -2009		
SPP	MISO	PJM
Exports to SERC	Exports to SERC	Exports to SERC
9,131	13,428	2,983

SERC Annual Flows (GWh) -2020		
SPP	MISO	PJM
Exports to SERC	Exports to SERC	Exports to SERC
12,900	15,899	3,841

The zonal flow into SERC may be accounted toward its RPS requirement provided other regions exceed their own requirement, which is assumed to be 15%. In Table 14, we present the actual wind generation.

Table 14. Annual Regional Wind Generation (2020)

Region	Wind Generation 2020 (TWh)	Wind Generation as % of Demand
SERC	29.87	2.56%
PJM	151.58	17.52%
MISO	144.06	20.18%
SPP	45.76	19.07%
NEW YORK	27.25	14.18%
NEW ENGLAND	23.70	15.98%

Note that Table 14 only includes the amount of wind generation within the region without giving any credits for imports. There is some excess wind developed in MISO, PJM, and SPP. However, the excess wind that is expected to be developed in these regions is not sufficient to cover the deficiency in SERC.

4. Alternative means to meet RPS goal in SE

Renewable energy resources are very location specific and the most economical deployment, particularly for wind energy, is generally not near population centers. This is illustrated in Figure 15 showing wind resources in blue and population centers in red and yellow. There is very little resource in the Southeast. If there were no transmission constraints in the eastern interconnect, the most economic deployment of wind would be in the Midwest with the energy transported to the east.

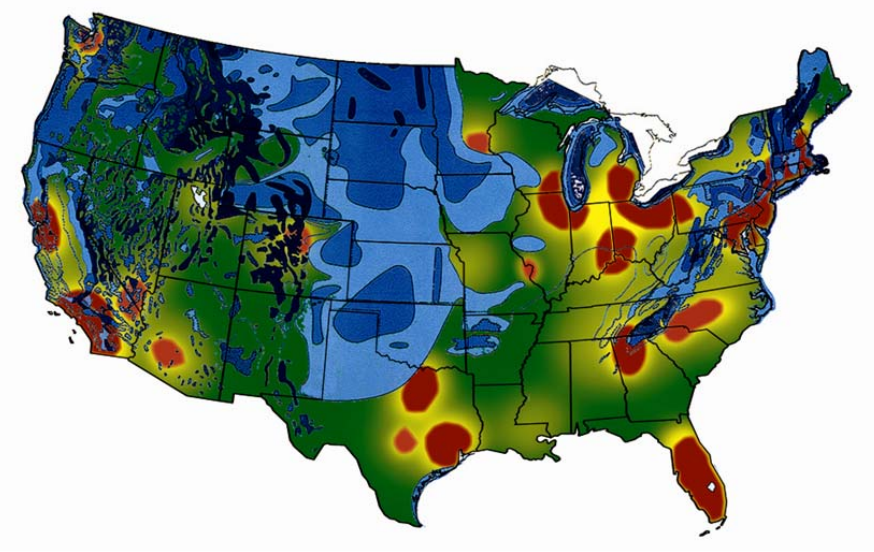


Figure 15. Wind Resources Relative to Population Centers.

Results in the JCSP and EWITS studies identify west to east transfers of wind energy that are primarily via upper Midwest to the eastern coast. Some energy transfer is expected to come from SPP to SERC Delta, and also via the Midwest to SERC Central. However, these transfers are relatively small compared to the available wind resources and compared to what would be needed to meet an RPS in the SERC and Florida regions.

4.1 RPS expectation with regional balancing of supply/demand

Federal policies, in particular related to CO_2 and RPS, are expect to affect the regional cost of electricity based on models that assume the historical regional balancing of supply and demand. One policy scenario is the new Bingaman RPS requirement. In its current configuration the bill allow trading of renewable energy credits in order to meet RPS requirements. Therefore areas of the country with more abundant renewable resources are expected to over-produce in order to earn and sell credits to other areas.

Under this arrangement, utilities in the south would need to purchase RECs from other regions. For example based on EPRI’s NESSIE model, with only an RPS policy (no carbon policy) the Southeast would requires 1017 TWh in 2020, and the electricity production from renewable resources would be ~113 TWh, which is 91 TWh short of the 20% RPS. External generation would provide the difference. In Florida the same EPRI model and scenario estimates that demand in 2020 is 282 TWh, and production from renewable resources is 9 TWh. With a 20%

RPS goal of 56 TWh, internal production from renewable energy of 48 TWh is short of the goal. Applying the cap REC price of 3¢/kWh (the ceiling in the Bingaman bill), there would be an estimated outflow of roughly $2.7 Billion from SERC and $1.4 Billion from Florida in 2020.

In order to better understand some of the different policy implications the EPRI NESSIE model was used to look first at the national picture and then for the Southeast and neighboring regions. Three policy cases were considered as summarized in Table 15.

Table 15. Three Possible Policy Scenarios, Source EPRI Report 1015805, March 2009 "Role of Future Generation Options for the U.S. Electric Sector"

Future Scenario	Name	PTC	RPS	CO_2 Price
No new policy	BAU	Yes	No	No
Federal RPS	RPS	Yes	Yes	No
Federal carbon policy	CO2	Yes	No	Moderate

- Load growth based on AEO 2008
- RPS policy assumptions based on the revised Bingaman Bill
- For carbon case, CO2 price in 2015 is approximately $27 per ton
- Natural gas prices vary from $4.91 to $7.28/MMBtu

4.1.1 *National RPS Levels with different Policies*

Results of modeling show that the economic deployment of renewable varies significantly depending on policies. The Figure 16, showing periods from 2010 to 2050, indicates that nationally a CO2 policy results in the highest deployment of renewable resources. It will also lead to a higher cost of electricity compared to the no policy or the RPS policy case.

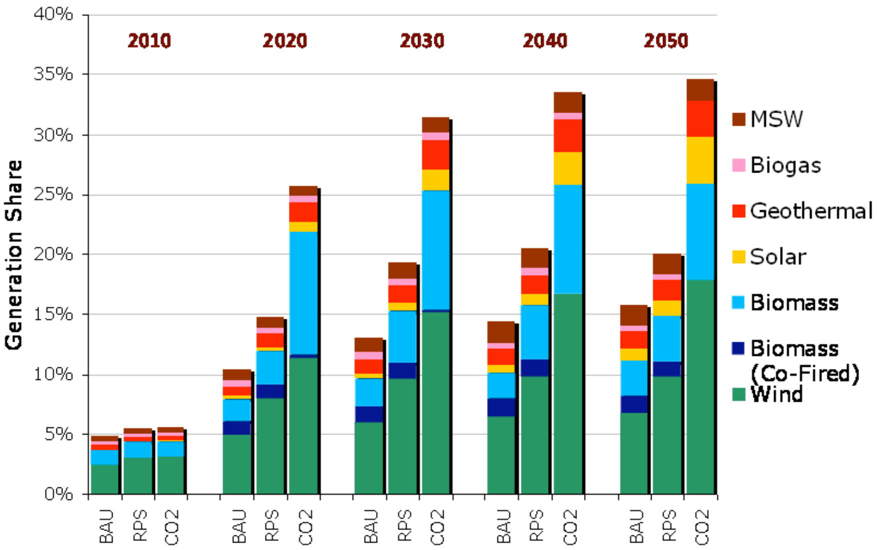


Figure 16. Renewable Share of Total Generation for Three Scenarios

A comparison of how national electricity demand would be met in the three different policy cases is provided in Figure 17. Note that the same demand is shown for each policy. A simplifying assumption was applied, where demand elasticity is not considered in the policy comparisons.

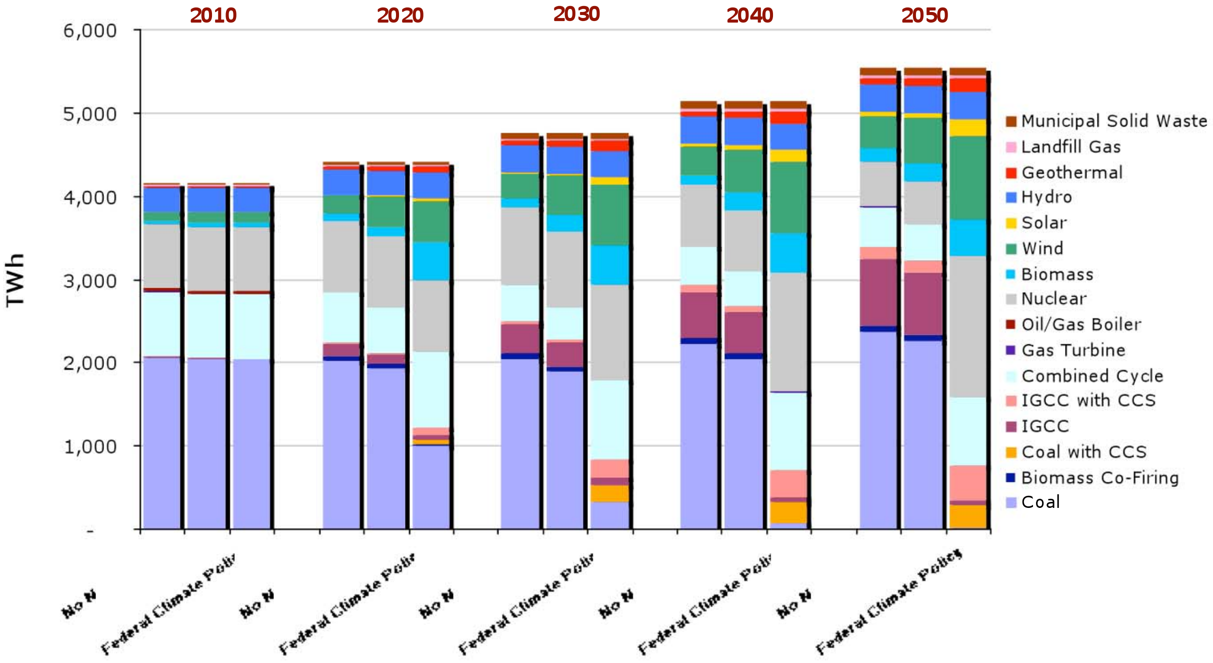


Figure 17. US Annual Electricity Generation under Different Scenarios (TWh)

NESSIE models the U.S. electric sector by carrying thirteen separate NERC regions. Nine of the 13 regions make up the Eastern interconnection. These regions are shown in Figure 1 above.

4.1.2 Eastern Interconnect and SE RPS Potential with different Polices

Modeling future scenarios for a large electric system depends on many, often subtle, factors in addition to the scenario assumptions. Capacity expansion and system operation are sensitive to load patterns, existing capacity, and commodity prices for both fuels and emission allowances. These vary from region to region.

In addition, renewable technologies depend on the extent and quality of wind, solar insolation, moving water suitable for hydro, and underground thermal. Also, the cost of delivered biomass fuel can vary. Differences in renewable resource availability represent an important factor for understanding the future LCOE that determines new capacity additions. In addition, the resource quality differences and the availability with respect to time of day (energy output profiles) help shape the production results for the regional systems. The deployment of renewable energy is expected to vary significantly from one region to another as shown in Figure 18. Also affecting the deployment is regional demand and competing generation options in a region.

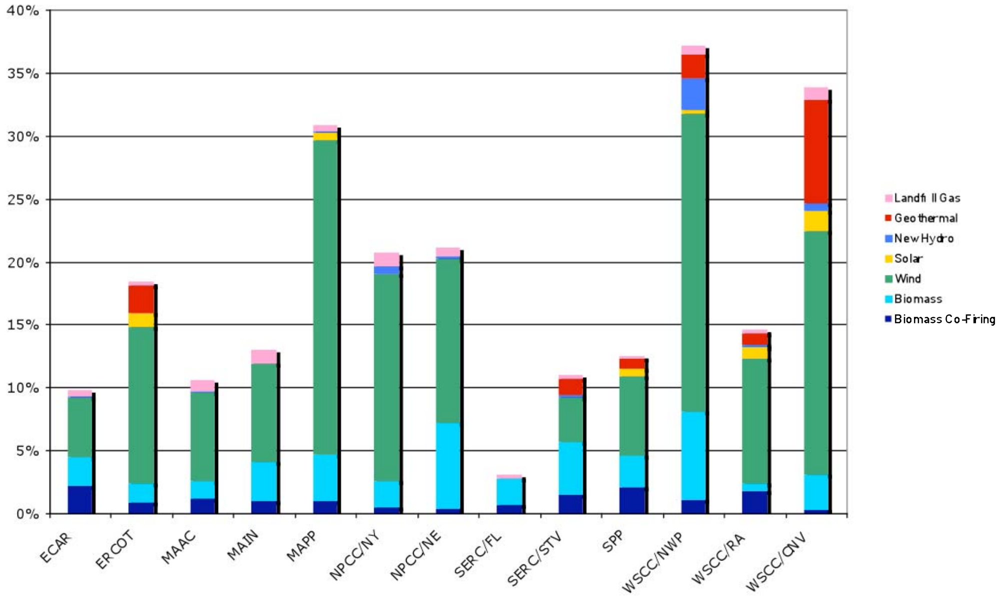


Figure 18. Regional Variation in Renewable Generation, RPS Policy Case (2020)

When considering where SERC/STV and Florida might import additional renewable energy the only apparent option in the RPS policy case shown above, is MAPP. However, most of the excess energy in MAPP and MAIN is spoken for by the east coast markets in MAAC, including PA, NJ, MD and Northern Virginia. There is abundant wind energy in SPP, however, other low cost generation options make wind investments less attractive. Also the relative size of electricity demand in the SE presents an additional challenge. As show in Figure 19 the SE plus Florida will consume about ~1300 TWh in 2020, which is more than 30% of the total consumption in the US.

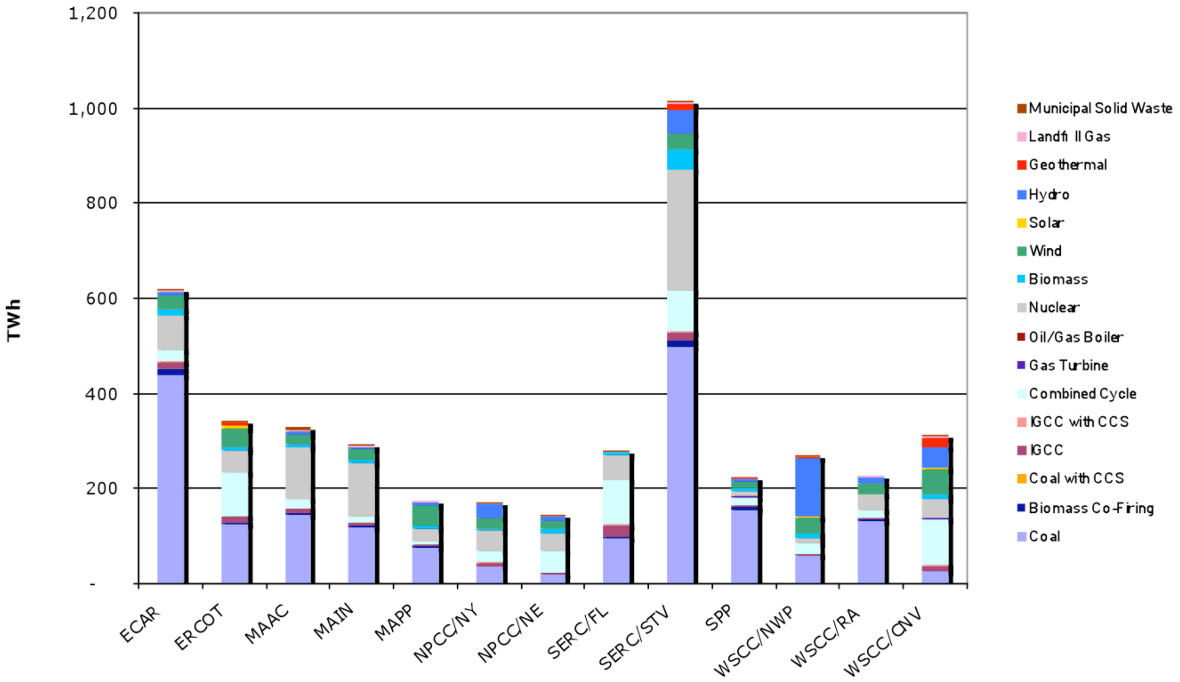


Figure 19. Regional Electricity Generation, RPS Policy Case 2020

The picture is expected to change significantly in all regions if there is a climate policy compared to the RPS case. For example in SPP almost three times more wind is deployed in the climate policy case than in the RPS case, see Figure 20.

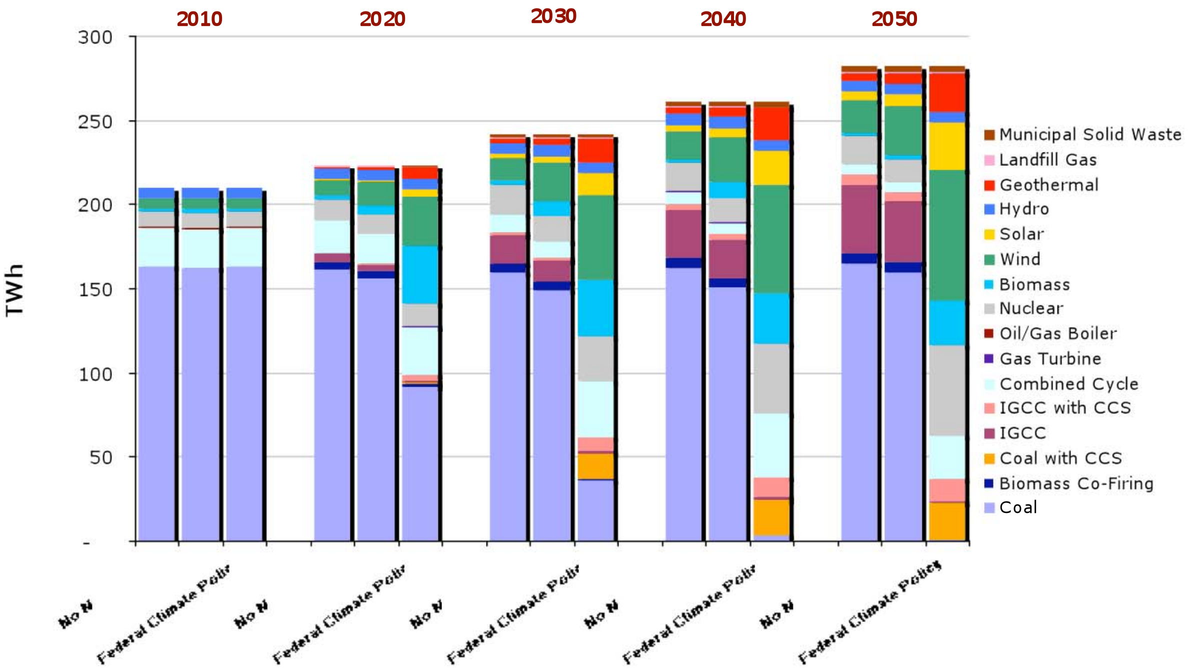


Figure 20. SPP Generation with no policy or federal RPS or federal climate policy

The increase of wind generation capacity in SPP occurs without any expectation for export to other regions. Since SPP is only harvesting about 1% of the wind resources, it is apparent that building for export could make a big difference in capacity expansion and transfer of wind energy to the SE. There is also an expected change in the deployment of renewable energy in all regions of the Eastern Interconnection if a CO_2 policy is enacted. Figure 21 shows the changes in generation in SERC and Figure 22 shows how the policy affects the cost of electricity in SPP, SERC/FL and SERC/STV.

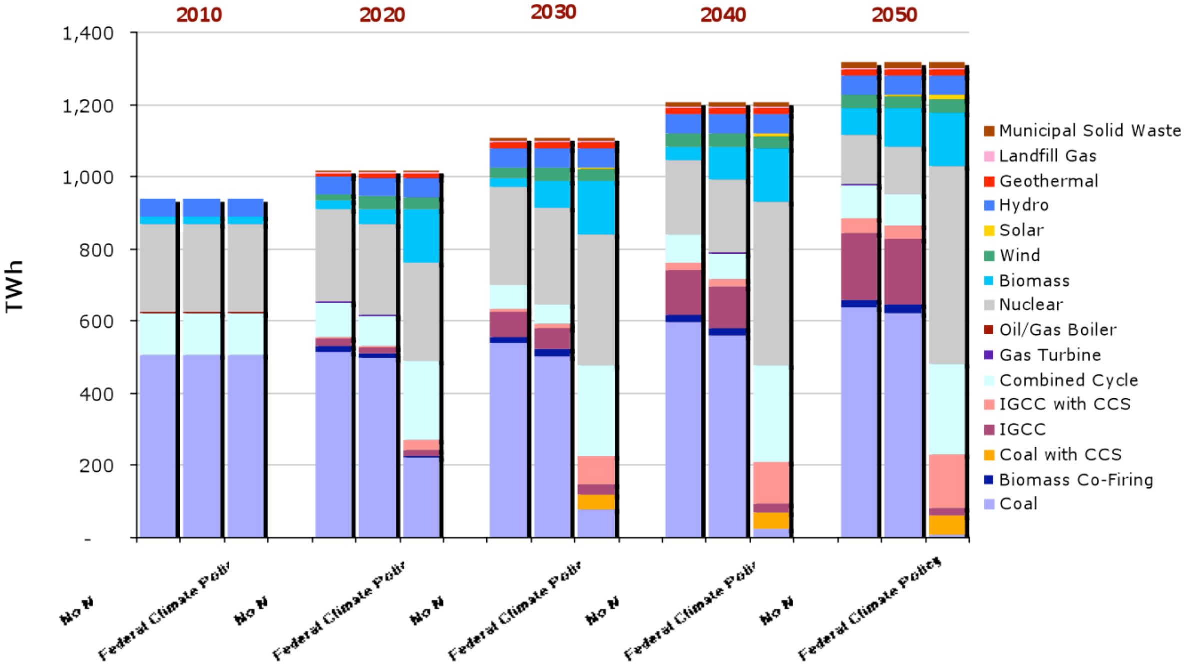


Figure 21 SERC Generation with no policy or federal RPS or federal climate policy

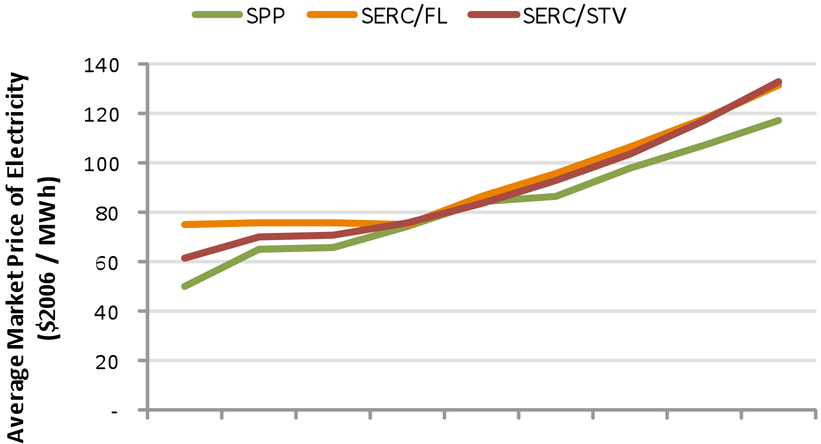


Figure 22. Comparison of Regional Cost of Electricity, CO_2 Policy Case

For the CO_2 Policy Case market prices from 2010 to 2050 for three regions; the levelized prices for the three regions are $69.58 per MWh in SPP, $75.62 in SERC/STV, and $81.97 in SERC/FL. These regional price differences are important for such metrics as customer satisfaction, asset values, and capacity retirements. As shown in the Figure lower prices in SPP early in the time horizon reflect good access to fuel markets and lower coal and natural gas prices; later, access to plentiful, high-quality renewable resources—especially wind, solar, and geothermal—provides an advantage as the CO_2 price accounts for a larger fraction of the wholesale price. Over the long run, the SERC/STV and SERC/FL have similar price trajectories reflecting similar fuel costs and renewable resource bases. However, SERC/STV has a more economic mix in the early years, which leads to the lower levelized market price.

There are more significant impacts of CO_2 policy in coal burning regions such as ECAR. In this case the cost of electricity in 2030 more than doubles from the no policy case, $40.50 per MWh to $89.50 per MWh with a moderate CO_2 policy. The cost of the RPS, without CO_2, policy is estimated to be $45.16/MWh. Figure 23 show the significant change in the generation mix in ECAR depending on the policy.

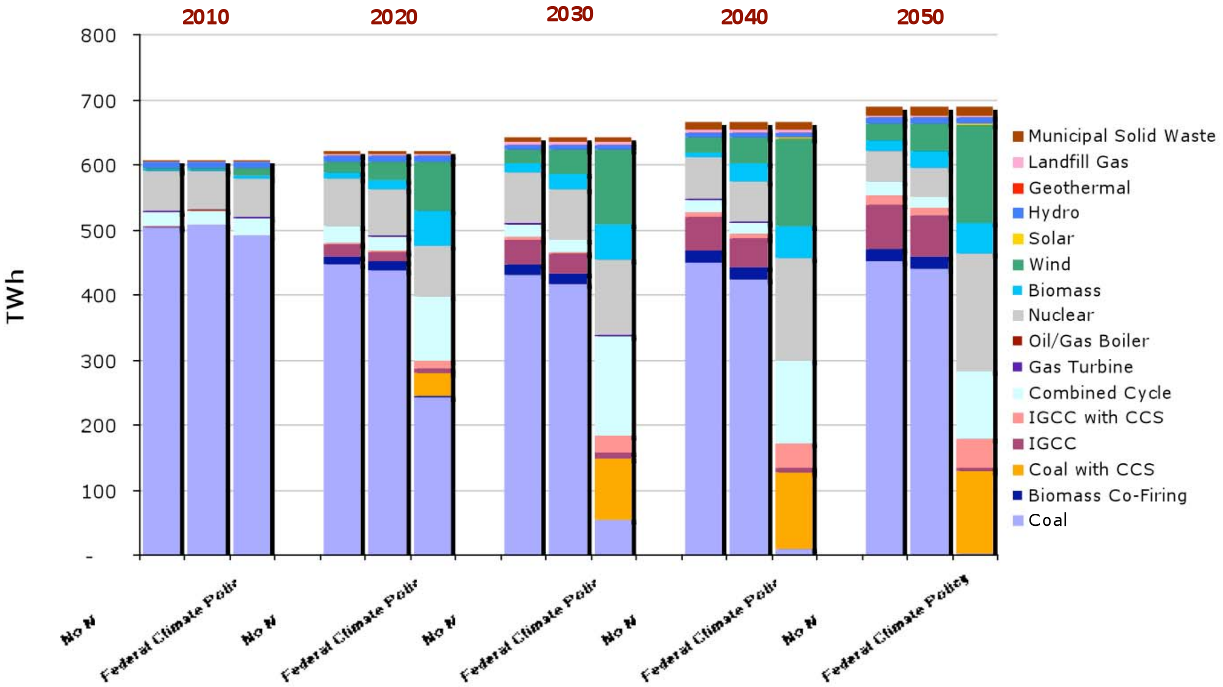


Figure 23 ECAR Generation with no policy or federal RPS or federal climate policy

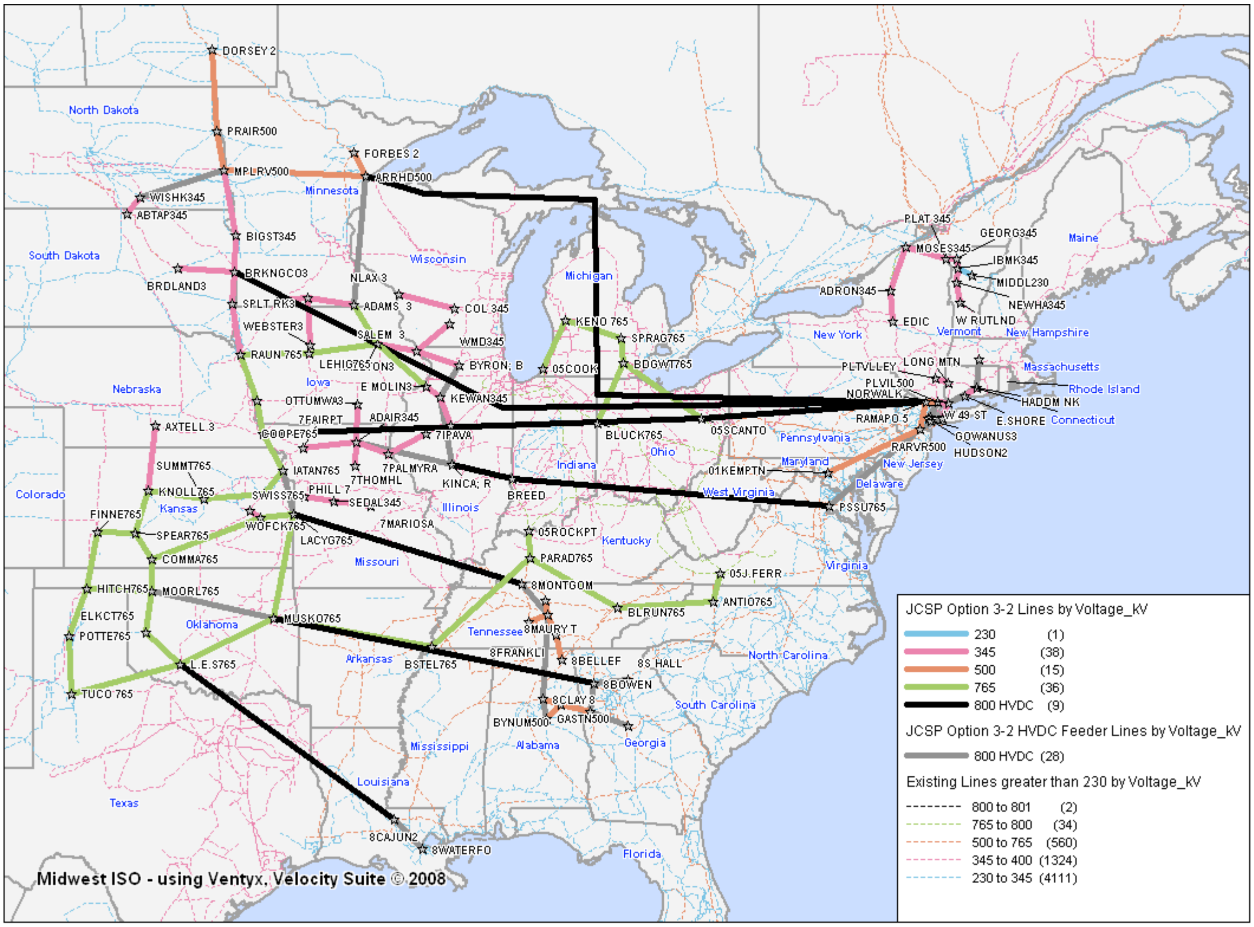
4.2 Other Studies

There are several studies either completed or currently being carried out by other groups. Two of these are looking at the interconnection needs to meet large wind transfers in the eastern interconnections.

The Joint Coordinated System Plan (JCSP 2008) analysis is “a conceptual regional transmission and generation system plan for a large portion of the Eastern Interconnection in the United

States, developed with the participation of most of the major transmission operators in the Eastern Interconnection. This initial effort looks at two scenarios that expand transmission and generation opportunities between 2008 and 2024 – a Reference Scenario and a 20% Wind Energy Scenario in support of the U.S. Department of Energy's Eastern Wind Integration and Transmission Study."

The analysis was a collaborative project between the Midwest ISO, SPP, PJM, TVA, MAPP, and some other members of SERC. The New York ISO and ISO New England participated as well, but later rejected the results because they felt more of their power would come from Canada than across the Midwest. While power flows to the southeast were analyzed, details on the amounts to the different subregions and to Florida were not examined. Figure 24 below from their report highlights the conceptual additional transmission lines required to meet 20% of generation from wind by 2024.



DORSEY 2
North Dakota
PRAIR500
FORBES 2
MPLRV500
ARRHD500
WISHK345
ABTAP345
Minnesota
BIGST345
South Dakota
BRKNGCO3
BRDLAND3
NLAX 3
Wisconsin
Michigan
SPLT RK3
ADAMS 3
COL 345
WEBSTER3
SALEM 3
KENO 765
SPRAG765
RAUN 765
WMD345
LEHIGT65
ON3
BYRON; B
05COOK
BDGWT765
Iowa
E MOLIN3
Nebraska
OTTUMWA3
KEWAN345
7FAIRPT
ADAIR345
AXTELL 3
COOPE765
7IPAVA
BLUCK765
Ohio
05SCANTO
Pennsylvania
SUMMT765
IATAN765
7PALMYRA
Indiana
KNOLL765
PHILL 7
7THOMHL
KINCA; R
BREED
01KEMPTN
Maryland
Colorado
Kansas
SWISS765
SEDAL345
Illinois
West Virginia
FINNE765
WOFCK765
7MARIOSA
SPEAR765
LACYG765
05ROCKPT
Kentucky
COMMA765
Missouri
PARAD765
05J.FERR
HITCH765
MOORL765
8MONTGOM
ANTIO765
ELKCT765
Oklahoma
MUSKO765
BLRUN765
POTTE765
Tennessee
8MAURY T
8FRANKLI
8BELLEF
8S_HALL
North Carolina
Arkansas
BSTEL765
L.E.S765
8BOWEN
TUCO 765
8CLAY 8
South Carolina
BYNUM500
GASTN500
Mississippi
Alabama
Georgia
Louisiana
Texas
8CAJUN2
8WATERFO
Florida
Midwest ISO - using Ventyx, Velocity Suite © 2008
PLAT 345
MOSES345
GEORG345
Maine
IBMK345
MIDDL230
ADRON345
NEWHA345
EDIC
W RUTLND
New York
Vermont
New Hampshire
PLTVLLEY
LONG MTN
Massachusetts
PLVIL500
NORWALK
Rhode Island
HADDM NK
RAMAPO 5
W 49 ST
E.SHORE
Connecticut
GOWANUS3
RARVR500
HUDSON2
New Jersey
Delaware
PSSU765
Virginia
JCSP Option 3-2 Lines by Voltage_kV
230 (1)
345 (38)
500 (15)
765 (36)
800 HVDC (9)
JCSP Option 3-2 HVDC Feeder Lines by Voltage_kV
800 HVDC (28)
Existing Lines greater than 230 by Voltage_kV
800 to 801 (2)
765 to 800 (34)
500 to 765 (560)
345 to 400 (1324)
230 to 345 (4111)

Figure 24. 20% Wind Energy Scenario Conceptual Transmission Overlay (*Source JCSP 2008)*

The JCSP scenario shown above was done in support of the DOE Eastern Wind Integration and Transmission Study (EWITS). This study is analyzing five scenarios: Reference; 20% – High Capacity Factor, On Shore Wind; 20% – Hybrid with Offshore Wind; 20% – Local, with Aggressive Offshore; and 30% – Aggressive On- and Off-Shore. The study is looking at operational impacts and costs from large-scale wind development and the benefits/costs of local versus remote wind generation strategies. Aside from TVA, the study is not including the Southeast in its study, although they do consider the regional demands in the analysis (Figure 25). The study is ongoing, with the final report not due until August 2009, but several interesting analyses have already been presented at seminars and workshops. For example, Figure 25 shows the interchange energy flows under Scenario 2, hybrid local and offshore wind generation.

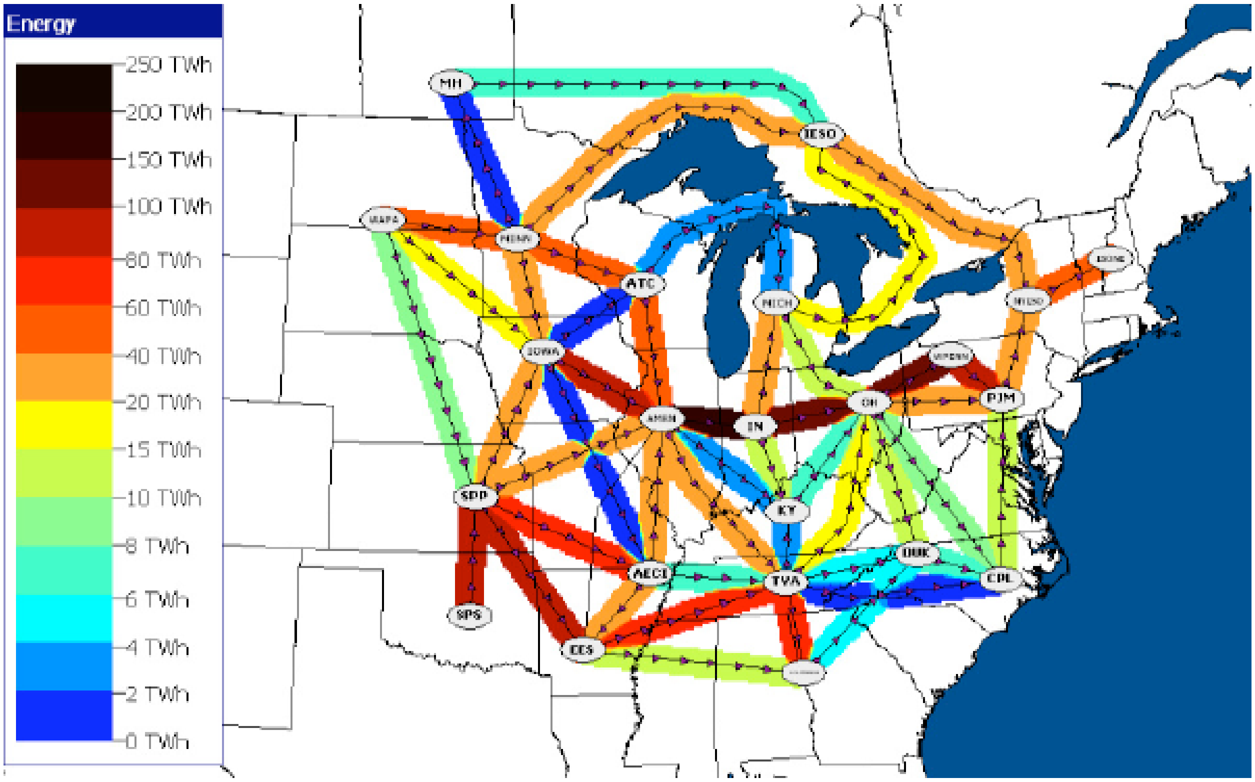

Energy
250 TWh
200 TWh
150 TWh
100 TWh
80 TWh
60 TWh
40 TWh
20 TWh
15 TWh
10 TWh
8 TWh
6 TWh
4 TWh
2 TWh
0 TWh
MH
IESO
ATC
IOWA
MICH
IN
OH
PJM
SPP
KY
DUK
AECI
TVA
CPL
SPS
EES

Figure 25. Scenario 2 Interface Contour: Annual Energy Difference Copper Sheet Minus Constrained Case (S*ource NREL 2009)*

5. Summary

Policies will have a big effect on the generation mix and the cost of electricity across the country. Some regions would build additional renewable capacity to meet their RPS, even though it may be higher cost than that generated elsewhere. However, with transmission constrained, regions with higher potential low-cost renewable capacity may not fully exploit that capacity and build for export. Similarly regions that do not have renewable resources are not likely to plan for imports.

Deployment of renewable generation is expected to increase significantly because of favorable policies and improvements in technology. This is true in all regions of the US. However, alternatives are limited for the Southeast to generate more than 10% of electricity consumption from renewable resources. The two main reasons are lack of renewable energy resources and relatively high consumption of electricity. Florida has the biggest challenge in this regard.

A policy for tradable renewable energy credits would provide one alternative for SERC and Florida to make up a shortfall in renewable energy. However this will be limited by the ability of other regions to produce and balance the higher percentage of variable renewable resources. It also represents a fairly large transfer of wealth in the case of the Southeast.

Several studies using different modeling tools (outlined in the sections above) all point to the need to import significant quantities of renewable power into the Southeast. Because of the magnitude involved, this would likely include both the energy and the balancing responsibility. This creates a rather substantial paradigm change in the way different regions plan to meet future demand. These massive imports and exports will also require new transmission infrastructure to enable the transfers. Such a paradigm shift will also require related regulatory changes and expansions of energy markets.

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Appendix A The Integrated UPlan Model

1. Introduction

LCG Consulting (LCG) is a widely recognized leader in modeling of competitive electricity and gas markets, for both market design and business planning. We are one of the first companies to research and quantify the implications of competitive pricing and marketing and develop models and database to analyze competitive power markets.

To address various business and regulatory issues in the evolving market environment, LCG has developed models for all aspects of short- and long-term operation and planning in the electric and gas utility industries. LCG has built integrated electricity generation and transmission models for all the ISOs and regions in the United States. Our international experience includes building nodal and zonal grid models for UK (1989), Spain (1991), and Russian (2003)). Currently we are developing an electric power and natural gas system simulator for the Greek Regulatory Authority for Energy (RAE). LCG's path-breaking study for California has set the standard for restructuring analysis throughout the U.S.

LCG's flagship model, UPLAN Network Power Model (UPLAN-NPM), is a full network model developed to replicate the engineering protocols and market procedures of an operator, and captures the commercial activities, such as bidding, trading, hedging, and contracting, of all players in a restructured power market. It projects detailed physical and financial operations of electricity markets conditions ranging from traditional regulation to today's post-restructuring competitive market structures. The model provides the consistent, structured framework, as well as the detailed quantitative inputs and results, required to evaluate the full implications of different fundamental drivers and market participant decisions.

UPLAN is capable of simulating all different types of generators such as thermal, hydro, wind and renewable, cogeneration and many other technologies. An in-line hydro scheduler dispatches hydro, pumped storage and CAES units daily and hourly to maximize net income. UPLAN can represent almost any kind of generation, transmission and a combination of loads. UPLAN unit commitment and dispatch algorithm performs coordinated marginal (opportunity) cost-based energy and ancillary service procurement, AC/DC optimal power flow (OPF), congestion management, full-fledged contingency analysis with Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED).

UPLAN-NPM is particularly suitable for optimizing generation and transmission simultaneously. Such an approach is necessary for evaluating renewable technologies such as wind, solar, and storages. Some of the recent renewable energy studies cited below provide examples of UPLAN's unique capabilities.

- ✓ Cost Benefit and Transmission Analysis: Cost benefit analysis of Texas Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study for Scenarios 1, 2, and 3. Testified before PUCT.
- ✓ Generation/Transmission Analysis: Complete RPS feasibility analysis for 2020 for ORNL/EPRI for Eastern Interconnection to determine the inter-zonal flows using UPLAN.
- ✓ Wind Integration: Large-scale wind development in ERCOT, MISO, PJM, New York and California (Multi-phase analyses for several clients)
- ✓ Transmission and Load Flow Analysis: Transmission investment and load flow analysis for several large wind farms in ERCOT, MISO, and PJM.
- ✓ Solar Power and Battery Integration: Solar study in Mohave and battery feasibility study in California, Washington, ERCOT and PJM.
- ✓ Storage Studies: LCG has undertaken several storage studies to analyze the feasibility of CAES in ECAR (Norton), ERCOT (AE), and several pumped storage plants in California.
- ✓ Coal Performance and Wind Integration: Several studies for global initiative were conducted for EPRI in the last five years.

2. UPLAN Network Power Model

UPLAN-NPM simulates the day-ahead energy and ancillary service market using a Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) similar to those used by most market operators in the country. In the first step of the SCUC, the model schedules day-ahead resources in appropriate amounts and locations to meet forecast energy (load) and ancillary service (reserve) requirements, while also taking into account region-specific operating protocols and transmission constraints. The Optimal Power Flow (OPF) simulation is then used to ensure that the final unit commitment can obey all transmission constraints, including line contingencies and generator outages.

The generators are dispatched to meet load in the most economical manner based on generator bids (costs) and subject to transmission constraints. It determines the hourly injection from the output levels of individual generators including renewable. The OPF simulation may utilize either DC or AC power flow, and the system will be optimally re-dispatched to manage congestion while obeying transmission constraints. The schematics of UPLAN are presented in Figure 1 below.

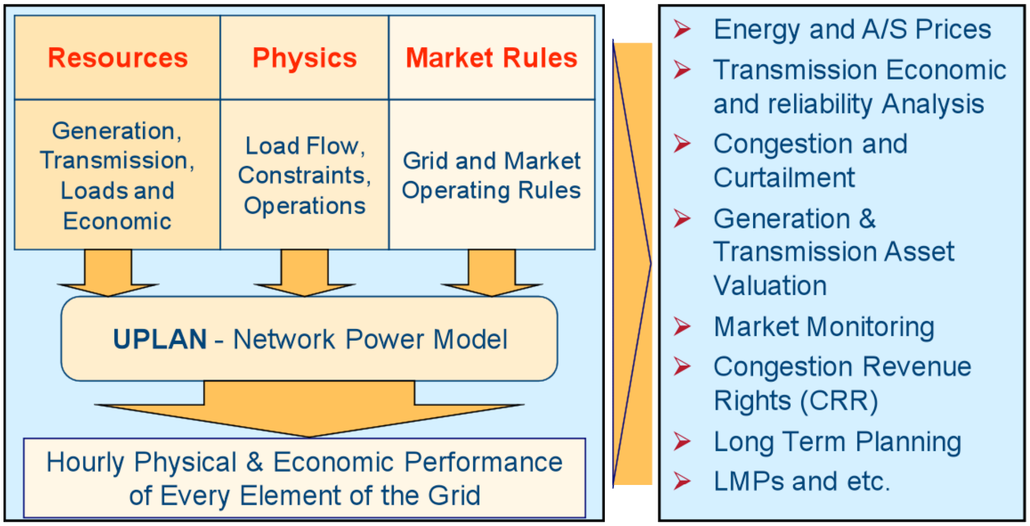

Resources
Physics
Market Rules
Generation, Transmission, Loads and Economic
Load Flow, Constraints, Operations
Grid and Market Operating Rules
UPLAN - Network Power Model
Hourly Physical & Economic Performance of Every Element of the Grid
Energy and A/S Prices
Transmission Economic and reliability Analysis
Congestion and Curtailment
Generation & Transmission Asset Valuation
Market Monitoring
Congestion Revenue Rights (CRR)
Long Term Planning
LMPs and etc.

Figure 1. Approach to Market Simulation in UPLAN

2.1 *Modeling Generating Plants in UPLAN*

The LCG Generator Database includes a wide range of generating technologies and variables that are salient to the diverse set of fuel type available, such as coal, gas, wind, hydropower and other renewable resources. A variety of bidding options are available on a unit basis that incorporate block heat rates, minimum up and down times, start-up costs, etc. Bidding behavior can be adjusted over time to reflect monthly load changes, scarcity, and so forth. Figure 2 summarized the generator characteristics modeled in UPLAN. The information for each generating or supply unit is currently stored as a record in the Generator Database as shown in Figure 3 below.

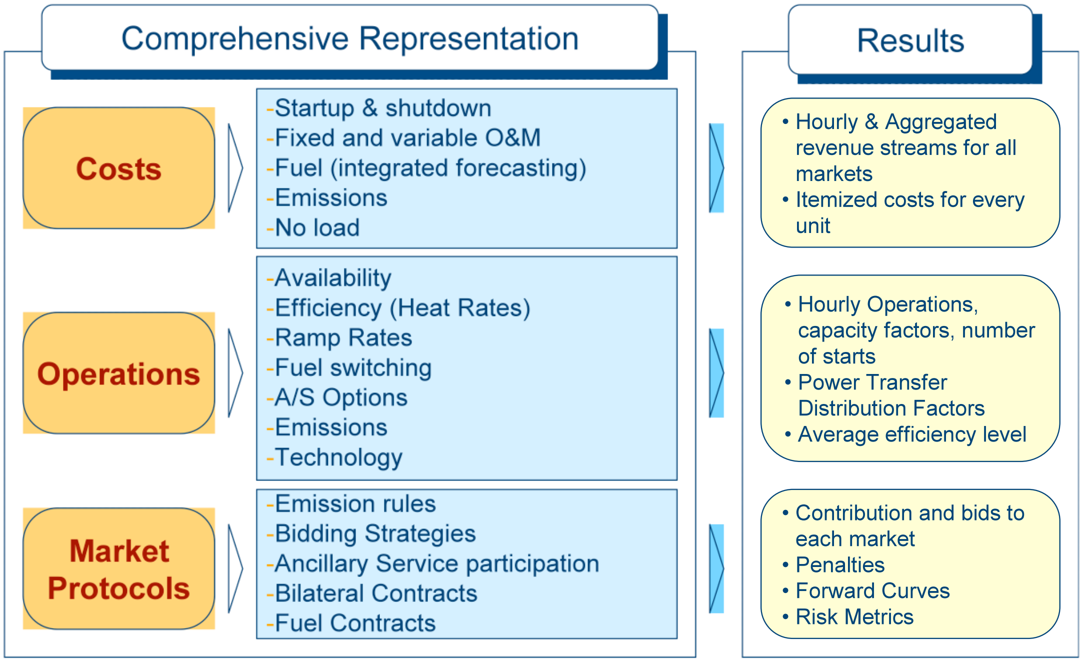
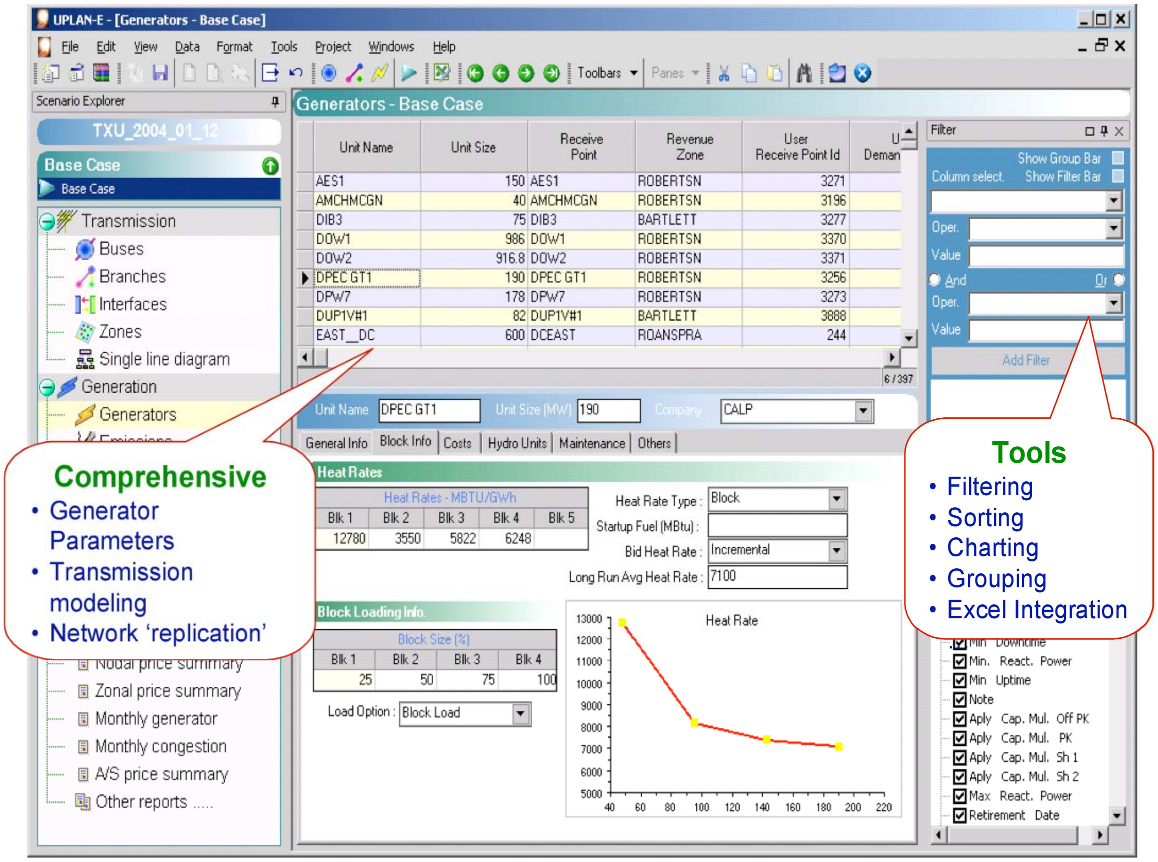

Comprehensive Representation
Results
Costs
-Startup & shutdown
-Fixed and variable O&M
-Fuel (integrated forecasting)
-Emissions
-No load
• Hourly & Aggregated revenue streams for all markets
• Itemized costs for every unit
Operations
-Availability
-Efficiency (Heat Rates)
-Ramp Rates
-Fuel switching
-A/S Options
-Emissions
-Technology
• Hourly Operations, capacity factors, number of starts
• Power Transfer Distribution Factors
• Average efficiency level
Market Protocols
-Emission rules
-Bidding Strategies
-Ancillary Service participation
-Bilateral Contracts
-Fuel Contracts
• Contribution and bids to each market
• Penalties
• Forward Curves
• Risk Metrics

Figure 2. Generator Characteristics Modeled in UPLAN


UPLAN-E - [Generators - Base Case]
File Edit View Data Format Tools Project Windows Help
Toolbars Panes
Scenario Explorer
TXU_2004_01_12
Base Case
Base Case
Transmission
Buses
Branches
Interfaces
Zones
Single line diagram
Generation
Generators
Emissions
Nodal price summary
Zonal price summary
Monthly generator
Monthly congestion
A/S price summary
Other reports .....
Generators - Base Case
Filter
Show Group Bar
Column select.
Show Filter Bar
Oper.
Value
And
Or
Oper.
Value
Add Filter
General Info
Block Info
Costs
Hydro Units
Maintenance
Others
Heat Rates
Block Loading Info.
Heat Rate
13000
12000
11000
10000
9000
8000
7000
6000
5000
40
60
80
100
120
140
160
180
200
220
☑ Min Downtime
☑ Min. React. Power
☑ Min Uptime
☑ Note
☑ Aply Cap. Mul. Off PK
☑ Aply Cap. Mul. PK
☑ Aply Cap. Mul. Sh 1
☑ Aply Cap. Mul. Sh 2
☑ Max React. Power
☑ Retirement Date
6 / 397

Unit Name	Unit Size	Receive Point	Revenue Zone	User Receive Point Id	U Deman
AES1	150	AES1	ROBERTSN	3271	
AMCHMCGN	40	AMCHMCGN	ROBERTSN	3196	
DIB3	75	DIB3	BARTLETT	3277	
DOW1	986	DOW1	ROBERTSN	3370	
DOW2	916.8	DOW2	ROBERTSN	3371	
DPEC GT1	190	DPEC GT1	ROBERTSN	3256	
DPW7	178	DPW7	ROBERTSN	3273	
DUP1V#1	82	DUP1V#1	BARTLETT	3888	
EAST__DC	600	DCEAST	ROANSPRA	244	

Unit Name: DPEC GT1
Unit Size (MW): 190
Company: CALP

Heat Rates - MBTU/GWh				
Blk 1	Blk 2	Blk 3	Blk 4	Blk 5
12780	3550	5822	6248	

Heat Rate Type: Block
Startup Fuel (MBtu):
Bid Heat Rate: Incremental
Long Run Avg Heat Rate: 7100

Block Size (%)			
Blk 1	Blk 2	Blk 3	Blk 4
25	50	75	100

Load Option: Block Load

Comprehensive
- Generator Parameters
- Transmission modeling
- Network 'replication'

Tools
- Filtering
- Sorting
- Charting
- Grouping
- Excel Integration

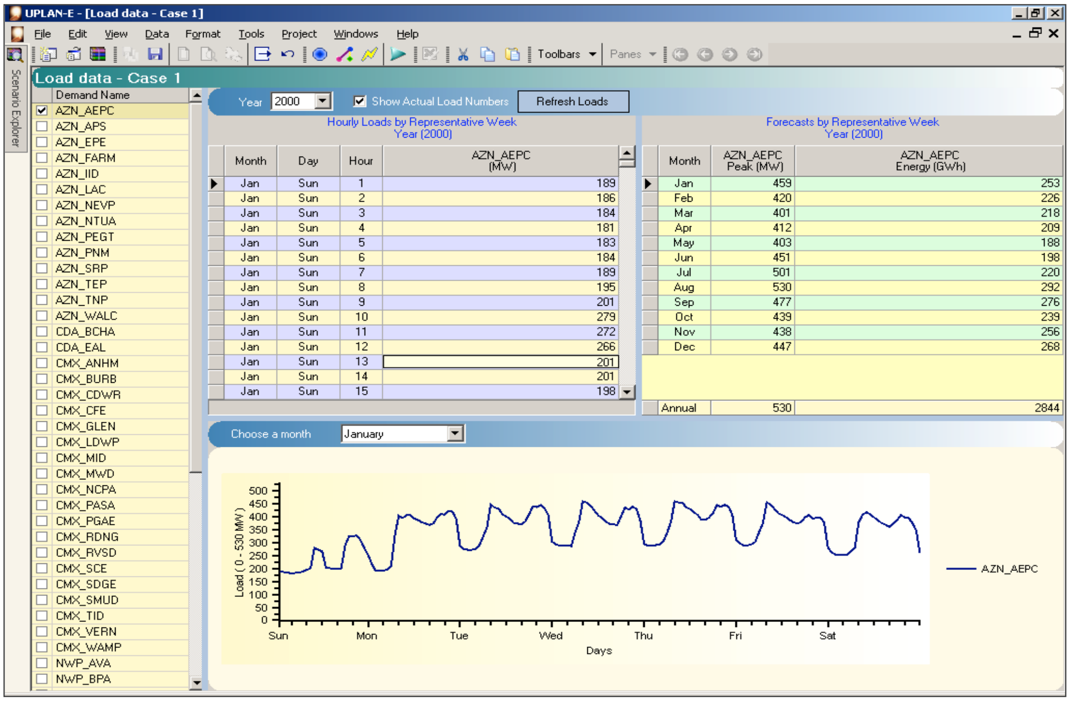
Figure 3. Detailed Presentation of Generating Assets

Each record consists of more than 250 fields of data including all characteristics of each supply unit, identified by a name and unique ID. The major categories of operating characteristics include availability, loading options, fixed, start-up and variable costs, and emissions rates. Fuel costs, fixed costs, and variable costs associated with running the generation units, and financial escalation rates or escalation schedules for these costs, are entered on a monthly basis.

System costs and operating characteristics of both existing and planned capacity are included in this database. General input data include financial escalation rates, unit commitment procedures and emissions categorization. Units may be made candidates for retirement, subject to the criteria set for emissions/new entrant analysis.

2.2 Modeling Loads in UPLAN

The UPLAN load module provides a way to create and manipulate load data. This module allows the user to add and remove a demand, manage yearly load profiles, manage monthly and annual load forecasts, display loads graphically (Figure 4).


UPLAN-E - [Load data - Case 1]
File
Edit
View
Data
Format
Tools
Project
Windows
Help
Toolbars
Panes
Scenario Explorer
Load data - Case 1
Demand Name
☑ AZN_AEPC
☐ AZN_APS
☐ AZN_EPE
☐ AZN_FARM
☐ AZN_IID
☐ AZN_LAC
☐ AZN_NEVP
☐ AZN_NTUA
☐ AZN_PEGT
☐ AZN_PNM
☐ AZN_SRP
☐ AZN_TEP
☐ AZN_TNP
☐ AZN_WALC
☐ CDA_BCHA
☐ CDA_EAL
☐ CMX_ANHM
☐ CMX_BURB
☐ CMX_CDWR
☐ CMX_CFE
☐ CMX_GLEN
☐ CMX_LDWP
☐ CMX_MID
☐ CMX_MWD
☐ CMX_NCPA
☐ CMX_PASA
☐ CMX_PGAE
☐ CMX_RDNG
☐ CMX_RVSD
☐ CMX_SCE
☐ CMX_SDGE
☐ CMX_SMUD
☐ CMX_TID
☐ CMX_VERN
☐ CMX_WAMP
☐ NWP_AVA
☐ NWP_BPA
Year 2000
☑ Show Actual Load Numbers
Refresh Loads
Choose a month January
500
450
400
350
300
250
200
150
100
50
0
Load (0 - 530 MW)
Sun
Mon
Tue
Wed
Thu
Fri
Sat
Days
AZN_AEPC

Hourly Loads by Representative Week
Year (2000)

Month	Day	Hour	AZN_AEPC (MW)
Jan	Sun	1	189
Jan	Sun	2	186
Jan	Sun	3	184
Jan	Sun	4	181
Jan	Sun	5	183
Jan	Sun	6	184
Jan	Sun	7	189
Jan	Sun	8	195
Jan	Sun	9	201
Jan	Sun	10	279
Jan	Sun	11	272
Jan	Sun	12	266
Jan	Sun	13	201
Jan	Sun	14	201
Jan	Sun	15	198

Forecasts by Representative Week
Year (2000)

Month	AZN_AEPC Peak (MW)	AZN_AEPC Energy (GWh)
Jan	459	253
Feb	420	226
Mar	401	218
Apr	412	209
May	403	188
Jun	451	198
Jul	501	220
Aug	530	292
Sep	477	276
Oct	439	239
Nov	438	256
Dec	447	268
Annual	530	2844

Figure 4. Chronological Hourly and Zonal Load Representation in UPLAN

UPLAN develops peak and energy based on econometric projections for the future years. It offers a variety of ways to determine the hourly load shapes for future years from the peak and energy forecast. The methodology depends on determining the load factor with minimum changes to the hourly profile. In each case the peak MW and total energy demand are used to modify the loads as described below.

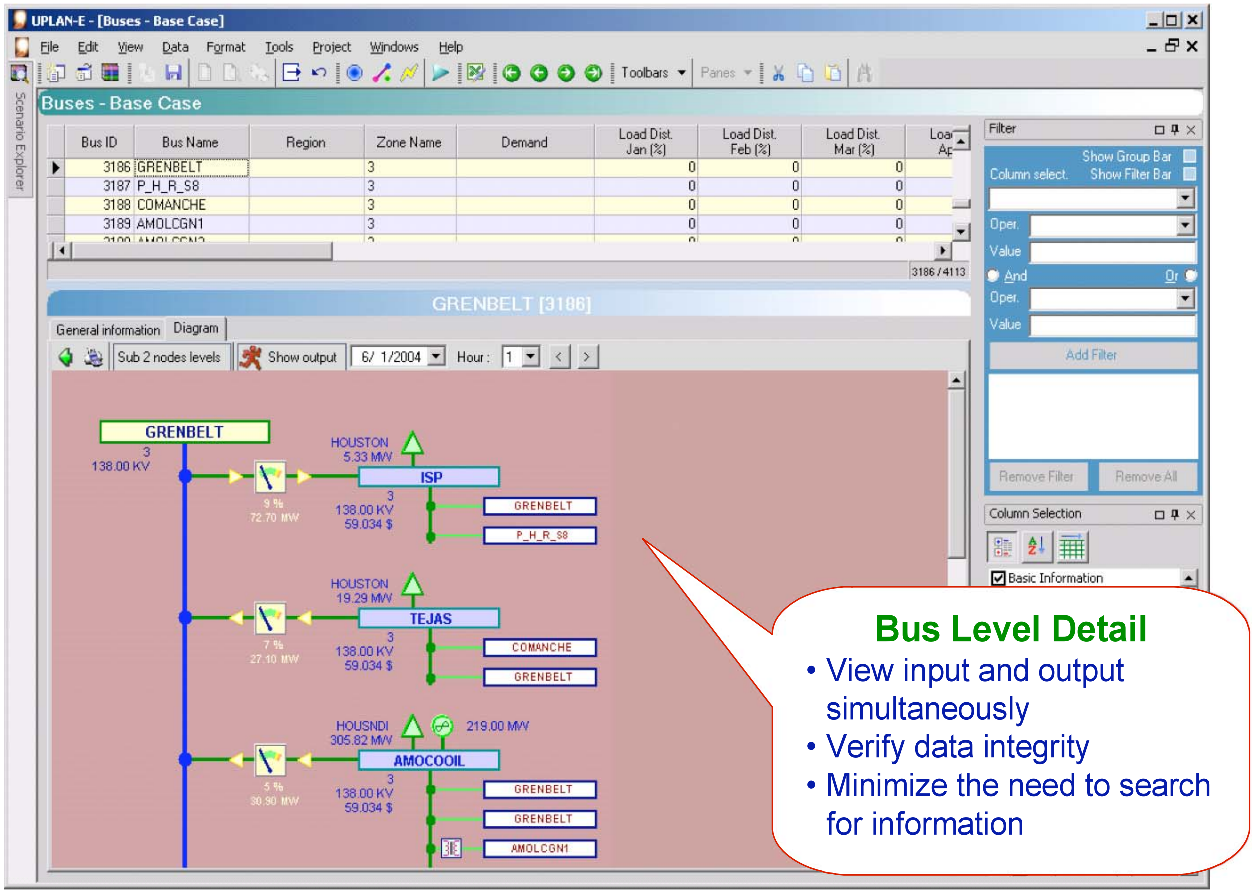
a. Static Load scaling – This method assumes that the load profiles are identical from one year to another. The load profile forecast is obtained by adjustment based on peak load forecast or energy demand.

b. Dynamic Load Scaling – This method assumes that the load profiles (from previous years) may be adjusted based on both the peak demand and the total energy. Two standard methods Mean-Bias Method and Valley Bias Method are employed to implement dynamic load modification.

Hourly chronological load at each control area is allocated to each bus according to participation factor.

2.3 Modeling Transmission

UPLAN is a full network model and has a sophisticated built-in load flow program which optimizes load flow twice every hour, once during unit commitment again during dispatch. The unique complete representation of transmission network allows the use of a full DC load flow for unit commitment and DC or AC dispatch for every hour's simulation. In this respect, UPLAN simulates the actual transmission grid operation and generator dispatch. The graphical display of UPLAN Transmission database is given in Figure 5.


UPLAN-E - [Buses - Base Case]
File
Edit
View
Data
Format
Tools
Project
Windows
Help
Toolbars
Panes
Scenario Explorer
Buses - Base Case
Filter
Show Group Bar
Column select.
Show Filter Bar
Oper.
Value
And
Or
Add Filter
Remove Filter
Remove All
Column Selection
Basic Information
3186 / 4113
GRENBELT [3186]
General information
Diagram
Sub 2 nodes levels
Show output
6/ 1/2004
Hour :
1
GRENBELT
3
138.00 KV
HOUSTON
5.33 MW
ISP
9 %
72.70 MW
3
138.00 KV
59.034 $
GRENBELT
P_H_R_S8
HOUSTON
19.29 MW
TEJAS
7 %
27.10 MW
3
138.00 KV
59.034 $
COMANCHE
GRENBELT
HOUSNDI
305.82 MW
219.00 MW
AMOCOOIL
5 %
30.90 MW
3
138.00 KV
59.034 $
GRENBELT
GRENBELT
AMOLCGN1

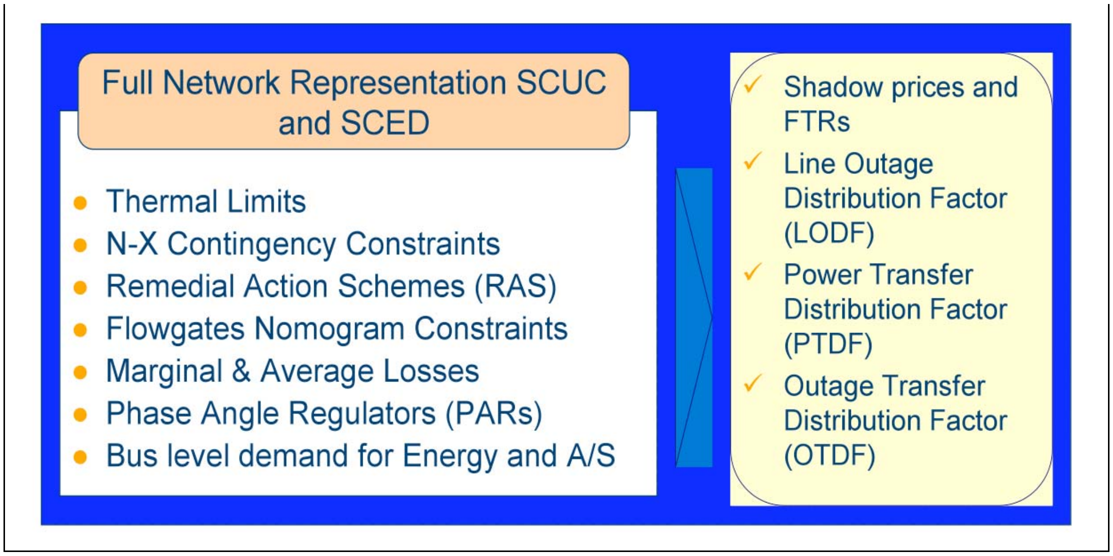
Bus ID	Bus Name	Region	Zone Name	Demand	Load Dist. Jan (%)	Load Dist. Feb (%)	Load Dist. Mar (%)
3186	GRENBELT		3		0	0	0
3187	P_H_R_S8		3		0	0	0
3188	COMANCHE		3		0	0	0
3189	AMOLCGN1		3		0	0	0

Bus Level Detail

- View input and output simultaneously
- Verify data integrity
- Minimize the need to search for information

Figure 5. Graphical Display of UPLAN Transmission Database

Other programs generally use a saved load flow program and linear sensitivity factor as replacement for the load flow and as a result unable to model many of the network characteristics shown in Figure 6 below.



Full Network Representation SCUC and SCED

- Thermal Limits
- N-X Contingency Constraints
- Remedial Action Schemes (RAS)
- Flowgates Nomogram Constraints
- Marginal & Average Losses
- Phase Angle Regulators (PARs)
- Bus level demand for Energy and A/S

- ✓ Shadow prices and FTRs
- ✓ Line Outage Distribution Factor (LODF)
- ✓ Power Transfer Distribution Factor (PTDF)
- ✓ Outage Transfer Distribution Factor (OTDF)

Figure 6. Transmission Network Characteristics Modeled in UPLAN

2.4 Ancillary Services Modeling

UPLAN simulations also reflect co-optimization of energy and ancillary service markets. To determine the economically optimal unit commitment, UPLAN realistically characterizes marginal opportunity cost-based bidding reflecting arbitrage across the different energy and ancillary service markets. Thus, a generator’s availability and willingness to sell various ancillary services depends on the resulting reduction of energy sales opportunities, and vice versa. Different A/S products (e.g., regulation, spin, non-spin, 30-minute, and reliability must-run) are integrated into UPLAN day-ahead market simulation. The ability of each generator to participate in each of the A/S market is specified in the generator input data.

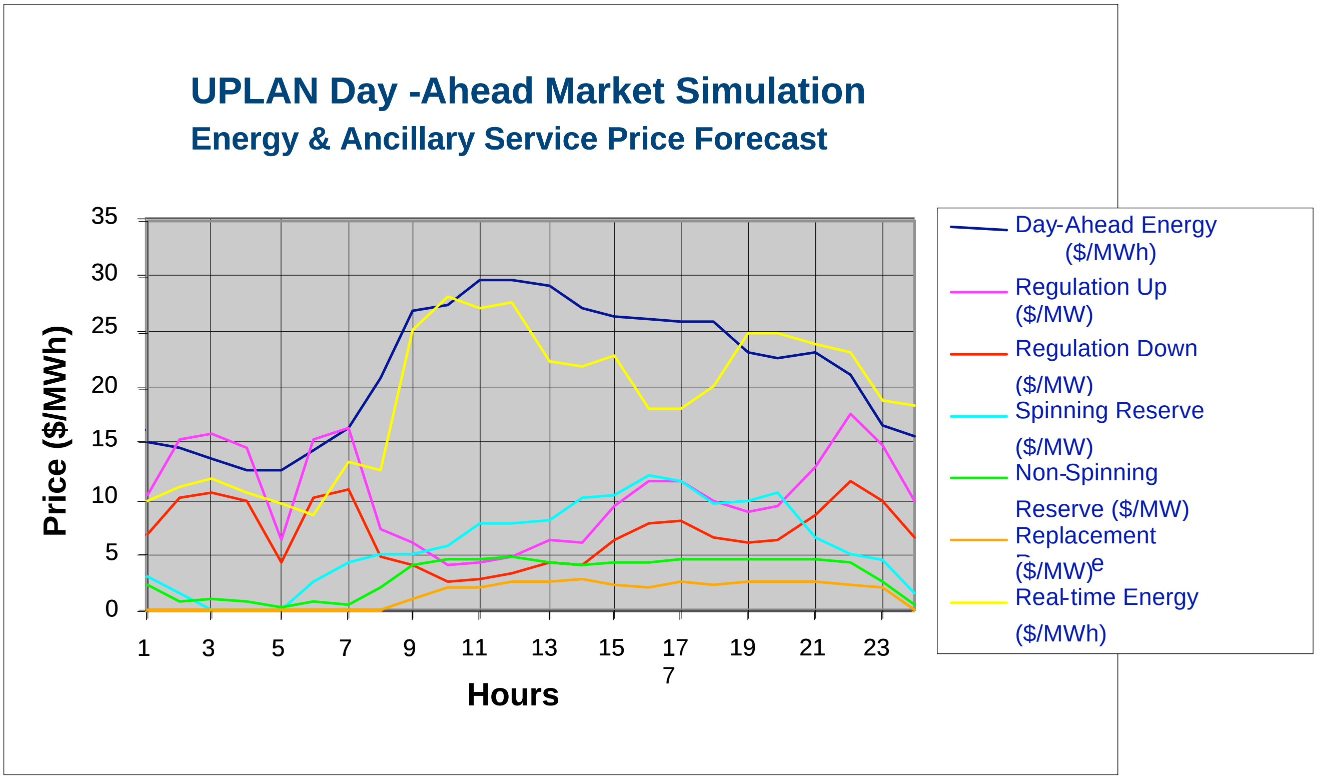
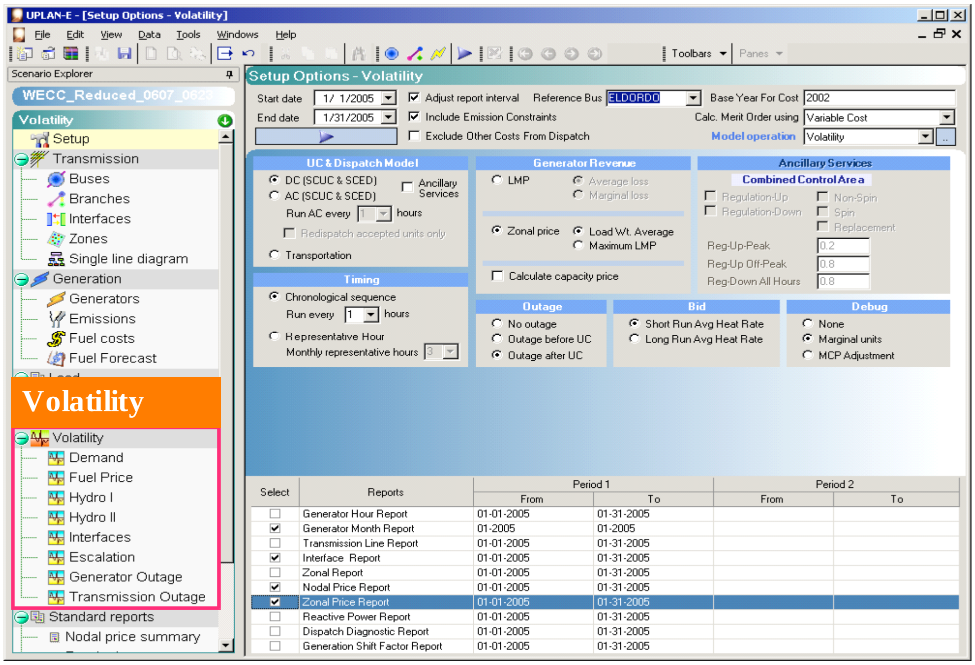


Figure 7. Energy and A/S Price Forecast in UPLAN

2.5 Volatility Model – Risk Analysis

The UPLAN Volatility Model enables the uncertainty of underlying fundamental drivers, such as load and fuel prices, to be effectively incorporated in developing forecast expected system operations and electricity prices. The real-time imbalance market is simulated by utilizing a Monte Carlo simulation of the demand, outages, and transmission derating, as well as other short-term volatilities.

For long-term simulation, the model can be used – along with long-term uncertainties of the fundamental drivers – to assess risks associated with any long-term generation or transmission investments and contracts. The model also produces probability distributions and expected values for LMPs, as well as net income distributions for generators, contracts, and the entire portfolio.


UPLAN-E - [Setup Options - Volatility]
File
Edit
View
Data
Tools
Windows
Help
Toolbars
Panes
Scenario Explorer
WECC_Reduced_0607_0623
Volatility
Setup
Transmission
Buses
Branches
Interfaces
Zones
Single line diagram
Generation
Generators
Emissions
Fuel costs
Fuel Forecast
Volatility
Volatility
Demand
Fuel Price
Hydro I
Hydro II
Interfaces
Escalation
Generator Outage
Transmission Outage
Standard reports
Nodal price summary
Setup Options - Volatility

Start date 1/ 1/2005
End date 1/31/2005
☑ Adjust report interval
☑ Include Emission Constraints
☐ Exclude Other Costs From Dispatch
Reference Bus ELDORDO
Base Year For Cost 2002
Calc. Merit Order using Variable Cost
Model operation Volatility

UC & Dispatch Model
● DC (SCUC & SCED)
○ AC (SCUC & SCED)
☐ Ancillary Services
Run AC every 1 hours
☐ Redispatch accepted units only
○ Transportation

Timing
● Chronological sequence
Run every 1 hours
○ Representative Hour
Monthly representative hours 3

Generator Revenue
○ LMP
● Average loss
○ Marginal loss
● Zonal price
● Load Wt. Average
○ Maximum LMP
☐ Calculate capacity price

Ancillary Services
Combined Control Area
☐ Regulation-Up
☐ Regulation-Down
☐ Non-Spin
☐ Spin
☐ Replacement
Reg-Up-Peak 0.2
Reg-Up Off-Peak 0.8
Reg-Down All Hours 0.8

Outage
○ No outage
○ Outage before UC
● Outage after UC

Bid
● Short Run Avg Heat Rate
○ Long Run Avg Heat Rate

Debug
○ None
● Marginal units
○ MCP Adjustment

Select	Reports	Period 1		Period 2	
		From	To	From	To
☐	Generator Hour Report	01-01-2005	01-31-2005		
☑	Generator Month Report	01-2005	01-2005		
☐	Transmission Line Report	01-01-2005	01-31-2005		
☑	Interface Report	01-01-2005	01-31-2005		
☐	Zonal Report	01-01-2005	01-31-2005		
☑	Nodal Price Report	01-01-2005	01-31-2005		
☑	Zonal Price Report	01-01-2005	01-31-2005		
☐	Reactive Power Report	01-01-2005	01-31-2005		
☐	Dispatch Diagnostic Report	01-01-2005	01-31-2005		
☐	Generation Shift Factor Report	01-01-2005	01-31-2005		

Figure 8. UPLAN Volatility Model

3. UPLAN Outputs and Applications

UPLAN provides a rich repertoire of output reports for electricity prices, generation and transmission in Excel format. A few of the reports are mentioned below.

Electricity Prices

- ✓ Hourly Locational Marginal Prices at each designated bus
- ✓ Zonal electricity and ancillary service prices
- ✓ Summarized peak, off-peak and monthly average prices for the duration of the simulation
- ✓ Price distribution for LMPs and zonal prices (output from Volatility Model)
- ✓ Call and put prices at designated strike prices
- ✓ Several other reports

Generation

- ✓ Electricity generation of each unit
- ✓ Production cost of each generator
- ✓ Gross and net revenues of each generating plant
- ✓ Marginal energy and capacity cost (LRMC)
- ✓ Size, timing, and technology of new capacity additions for each market area
- ✓ Annual capital expenditure for each new and existing plant
- ✓ Retirement of the existing units

- ✓ Life extension of the existing units

Transmission

- ✓ Line flow
- ✓ Zonal congestion
- ✓ Total transmission capacity (TTC)
- ✓ Available transmission capacity (ATC)
- ✓ Binding contingency
- ✓ Voltage Violation/Capacitor Dispatch

Financials

- ✓ Costs and revenues of each resources
- ✓ Performance of bilateral contracts
- ✓ Congestion revenues and CRRs
- ✓ Transmission and congestion contracts (TCCs)
- ✓ Zonal flows and revenues
- ✓ Energy and ancillary services prices and call/put option values
- ✓ Generator revenues, net income and call/put option values at various strike prices
- ✓ Gamma, Delta, Theta and other Greeks
- ✓ Value at Risks, value of call/put premiums for all resources including CRRs

In Sum, UPLAN offers the following functional capabilities:

- Day-Ahead Security Constrained Unit Commitment process and Security Constrained Economic Dispatch
- Congestion management in day-ahead and during dispatch
- Use of transmission constraints and resolve all congestion in the day-ahead markets
- Distributed marginal (or average) losses for unit commitment and dispatch
- Co-optimization of energy and ancillary services
- LMPs for energy at every node and A/S prices at every ISO controlled Zone
- Zonal as well as Nodal modeling
- Volatility analysis for generator and transmission valuation as well as capacity expansion

4. A Common Database for Generator, Transmission, and Customer Load

UPLAN-NPM operates in an efficient and powerful ***MS SQL Server*** environment using the latest technologies to rapidly view, manipulate and manage the large, complex data sets necessary for realistic market simulation and analysis. It is conveniently addressed via “scenario” based storage, freeing the user from many laborious data management tasks and minimizing the risk of overwriting or accidentally deleting data. UPLAN-NPM offers an integrated environment to view or modify all input data, with both standard and customized reporting. Its intuitive interfaces contain countless time saving features, including sorting, grouping, filtering, data validation, seamless Excel integration and custom charting, see Figure 9.

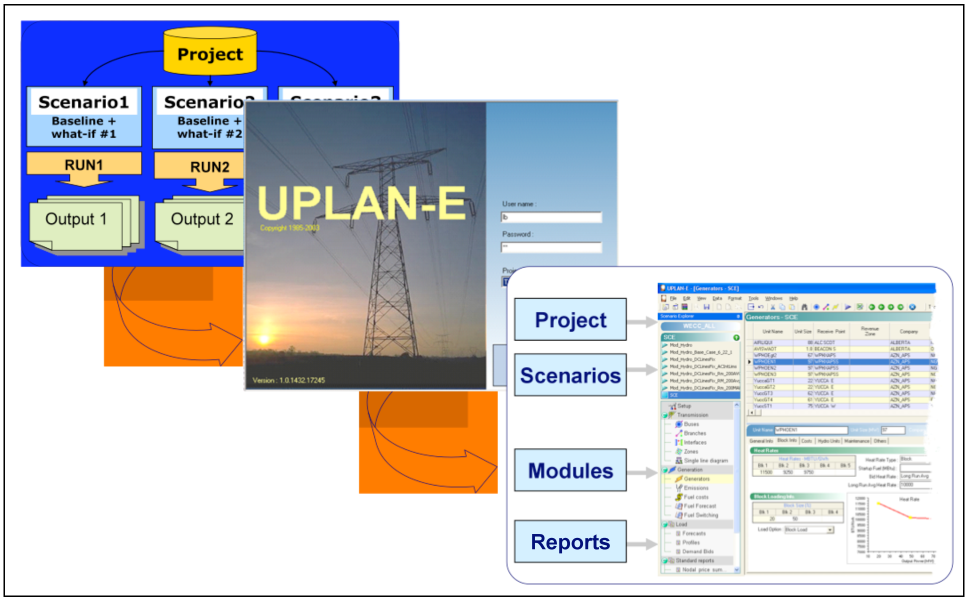

Project
Scenario1
Baseline + what-if #1
RUN1
Output 1
Scenario2
Baseline + what-if #2
RUN2
Output 2
UPLAN-E
User name :
Password :
Version : 1.0.1432.17245
Project
Scenarios
Modules
Reports

Figure 9. UPLAN User Interface Database Structure

The UPLAN database is organized as a relational database with a global store for all the input information. It is further organized in projects and scenarios for ease of use, management, and security. Since it is a standard RDBMS system, there is transparency and flexibility as to the data. Tasks, such as incorporating external data or exporting UPLAN data to XML, are easily accomplished. Furthermore, no distinction is made between input and output so that users can seamlessly make excursion to input and output database to create new reports, perform economic input and output analysis, and store results for future use.

The integrated UPLAN models and database provide a solid foundation for modeling, database management and performing all planning functions.