

A Multiperiod Generalized Network Flow Model of the U.S. Integrated Energy System

Part II – *Simulation Results*

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Abstract—This paper is the second of a two-part paper and describes the application of a multiperiod generalized network flow model that is used to analyze the economic efficiencies of the energy movements from the coal and natural gas suppliers to the electric load centers, providing a simulation tool that captures dynamics of and interdependencies between the coal, natural gas, and electricity networks. The modeling approach, mathematical formulation, and modeling assumptions are presented in part I. This sequel presents and discusses numerical results to illustrate the application of the model. The model enables public and private decision makers to carry out comprehensive analyses of a wide range of issues related to the energy sector, such as strategic planning, economic impact assessment, and different regulatory regimes.

Index Terms— **Generalized network flow model, integrated energy networks, nodal prices, optimization.**

I. INTRODUCTION

IN the first part of this two-part paper, a network flow model of the U.S. integrated energy system is presented [1]. The mathematical formulation and the modeling assumptions are described. Conceptually, the model represents the coal, gas, and electricity systems, structured as a generalized, multiperiod network composed of nodes and arcs. Under this approach, fuel supply and electricity demand nodes are connected via a transportation network and the model is solved for the most efficient allocation of quantities and corresponding prices. The synergistic action of economic, physical, and environmental constraints produces the optimal pattern of energy flows.

This second part of the paper demonstrates the applications of the model. The remainder of this paper is organized as follows. Section II presents the complete procedure for

obtaining the solution of the optimization problem and visualizing the results. The model validation is addressed in section III. Results of three case studies are provided and discussed in section IV. Section V deals with the tradeoffs between alternative energy transportation modes. Directions for future work, potential model applications, and concluding remarks follow in sections VI, VII, and VIII, respectively.

II. PROCEDURE

The complete procedure for obtaining the solution of the optimization problem described in part I of this paper can be divided into four main tasks: data gathering, matrix generation, optimization, and results visualization, as summarized in the flowchart of Fig. 1.

The first step is to identify the relevant sources of information. Once data have been collected and the gaps resolved, the next step is to create the data input files. These are delimited text files and include the “nodes.txt” and the “arcs.txt” files. The first is a list of all the nodes and associated supply/demand. The other is a list of all the arcs and related information, including origin node, destination node, lower bound on the flow, capacity, efficiency rate, and per unit cost. Both “nodes.txt” and “arcs.txt” characterize a single time step representation of the network. In addition to these two files, other input files are created with data pertaining to time-variant parameters (e.g., load data for each specific demand region or generation capacity additions).

The second step is to generate the node-arc incidence matrix (or, more generically, the constraint coefficient matrix) in MPS format [2]. If a multiperiod simulation is desired, the input files “nodes.txt” and “arcs.txt” are expanded according to the user specified time steps for each energy subsystem, and the time-variant parameters updated. Then, the MPS format data file is created. This entire task (including the expansion of the network and the generation of the MPS format data file) is implemented in MATLAB [3].

The third step, optimization, is performed in CPLEX [4]. After reading the MPS data file, CPLEX preprocesses the problem in an attempt to reduce its size, which is, in general, beneficial for the total solution speed. Opportunities to reduce the size of the problem arise through the simplification of constraints and elimination of redundancy. For example, nodes with indegree of 1 and outdegree of 1 (i.e., nodes with

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only one incoming arc and one outgoing arc) may be eliminated and the parameters of the equivalent arcs adjusted. Nonetheless, CPLEX reports the model's solution in terms of the original formulation, making the exact nature of any reductions immaterial to the user. After preprocessing the problem, the network optimizer routine is called to solve the problem. The problem need not be entirely in network form, as is the case when the emissions constraint is included, as explained in part I of this paper. In this case, CPLEX automatically relaxes the side constraint and solves the network portion using the network simplex algorithm. Then, CPLEX performs standard linear programming iterations on the full problem using the network solution to construct an advanced starting point. If no side constraints exist, CPLEX solves the entire problem directly using the network simplex algorithm. When the optimization is complete, solution information is written to a standard solution file in text format. The solution file contains the value of the variables (the optimal flows) and the dual activities or nodal prices associated with the constraints.

Fig. 1. Flowchart of the complete procedure.

The fourth and last step is performed using the visualization capabilities of ArcView 9.1 to display the networks and the simulation results on a map [5]. Using this geographic information system software allows us to better understand the geographic context of the results and identify patterns. First, the networks are converted into shapefiles, i.e. thematic layers and datasets with a geographical reference. Shapefiles are created directly by digitizing shapes using ArcView feature creation tools. Simulation results are then converted into databases with the appropriate field structure, appended to the associated shapefile attribute table, and displayed with graduated symbols, colors, charts, or any other of the available tools in ArcView.

III. MODEL VALIDATION

To check the accuracy of the model and to provide benchmark results that approximate the actual network flows, the reference case is designed with the actual configuration of generation, loads, and emissions reported for the year 2002. This year was used for being the most recent year for which complete data were available to characterize all different energy systems. Fixing generation provides that the flows along the mid-stream part of the overall transportation model are forced to be the same as the historical flows in those arcs (see Fig. 2). Generation data are derived from the Energy Information Administration Form 906 and loads are obtained from the Electricity Supply and Demand database maintained by the North American Electric Reliability Council. Emissions data are gathered from the Allowance Tracking System of the Environmental Protection Agency. The coal and natural gas flows are optimized to achieve the least cost solution that corresponds to the actual generation, load, and emissions levels. This historical configuration is a feasible solution for the network flow model, resulting in the coal and natural gas deliveries and SO₂ allowance price shown in Table I.

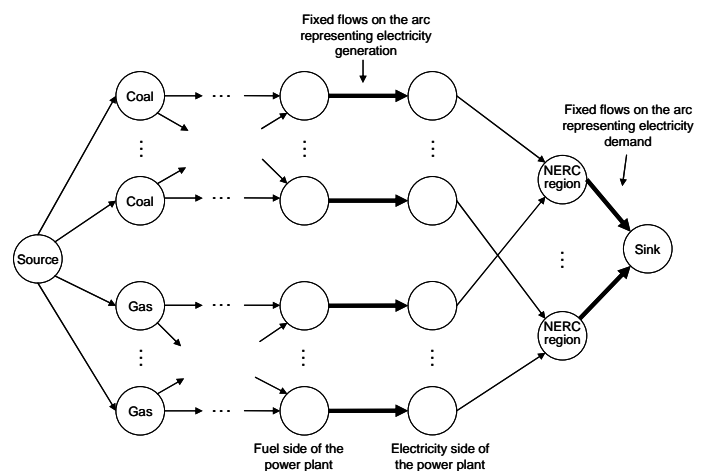
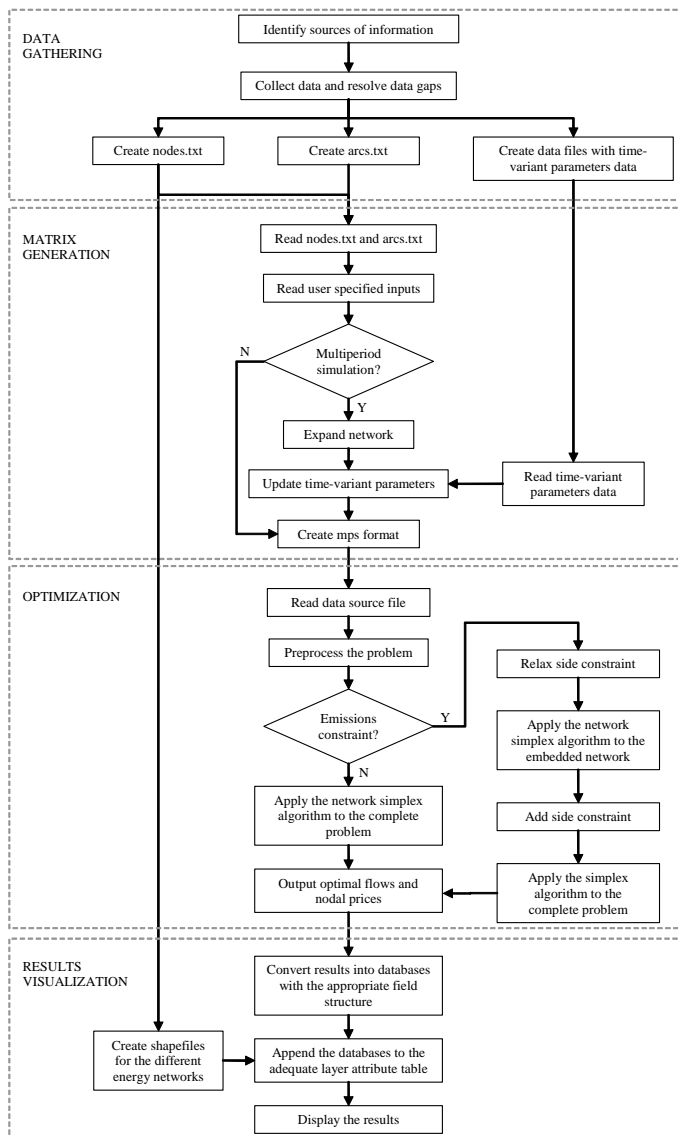


Fig. 2. Schematic representation of the network configuration in the reference case.

TABLE I
VALIDATION RESULTS

Result	Model	Actual	Difference
Coal deliveries (million tons)	953	976	2.35%
Natural gas deliveries (Bcf)	5,125	5,398	5.06%
Allowance price (\$)	98	130	24.61%

The coal and natural gas deliveries to power plants approximate the actual values, with the errors being 2.35% and 5.06%, respectively. This provides an indication that the data concerning the heat values for the different types of coal and natural gas and the generators' heat rates are adequate.

The allowance price obtained from the model (\$98 per allowance) is the nodal price or dual variable associated with the emissions constraint. This reflects the marginal cost of compliance, or the penalty level for emitting an additional ton of SO₂, given the modeling assumptions and under an optimized coal production and transportation pattern. Actual allowance prices for 2002 ended the year in the \$130 range [6]. The discrepancy between the model result and observed allowance prices are due to the following reasons:

- Because coal flows are optimized to achieve the least cost solution that corresponds to the actual generation and emissions levels, the outcome overestimates the utilization of low-priced, low-sulfur coal (relative to historical use), which results in an underestimation of the allowance prices.
- The market price of allowances is largely based on expectations of their future value, an influence that is not modeled. There are three main uncertainties which drive allowance prices:
 - i) Since power plants use banked allowances to comply with the stringent Phase II requirements of the Clean Air Act Amendments [7], banks are expected to continue to be depleted. This suggests that power plants are likely to be anticipating more expensive abatement efforts (including retrofitting units with scrubbers) for meeting compliance requirements in the future. The prediction of future expenditures on abatement technologies would tend to increase allowance prices.
 - ii) As natural gas prices increase, the option of fuel switching for compliance with the provisions of the SO₂ cap and trade program becomes less attractive, placing an upward pressure on allowance prices.
 - iii) The anticipation of tighter emissions constraints (e.g., the Clean Air Interstate Rule) and uncertainty regarding future environmental policies to meet air quality standards are other factors contributing to an actual higher allowance price than the one predicted by the model.

An approach to address the influence of perceived future conditions is identified in section VI.

This configuration with actual generation, load, and emissions and optimized coal and natural gas flows is denoted as the reference case. The reference case is used in the following section as a benchmark for comparison with the global optimal solutions with and without emissions

constraint.

IV. CASE STUDIES

A. Overview

This section shows the results of three case studies:

- i) **Case A:** reference case solving for optimized coal and natural gas flows conditioned on actual generation, demand, and emissions data from 2002;
- ii) **Case B:** a modification of the reference case where only demand is fixed (generation is not fixed) and without emissions constraint;
- iii) **Case C:** same as case B, except that the emissions constraint is now imposed.

In essence, case A is constrained to supply demand through generation consistent with 2002 generation history, whereas cases B and C are allowed to freely optimize subject to capacity constraints and, in case C, emissions constraints. Comparison of case A to cases B and C provide insight into the difference between total cost in 2002 and what could be achieved in the optimal cases. The costs considered are (i) the coal production and transportation costs, (ii) the natural gas production, transportation, and storage costs (including the costs of producing, transporting, and storing natural gas to supply the non-electric sector), and (iii) electric power transmission costs, as defined in the modeling assumptions presented in part I. All cases are simulated with yearly data for the coal network and monthly data for the natural gas and electricity networks. In each case, the network flow model is composed of 1290 nodes and 3480 arcs. There is no modeling limitation to consider smaller time steps and/or provide more granularity to any of the energy subsystems, as long as appropriate data are available to enable it. The results are obtained using the network optimizer routine of CPLEX 8.1 in a 2.8 GHz Pentium 4 processor with 1 GB of RAM. The computing time is less than 0.5 seconds for each of the considered case. Table II presents the summary results.

TABLE II
SUMMARY RESULTS

Result	Case A	Case B	Case C
Coal deliveries (million tons)	953	1,054	1,048
Natural gas deliveries (million Mcf)	5,125	3,615	3,615
Electricity generation from coal (thousand GWh)	1,910	2,117	2,116
Electricity generation from natural gas (thousand GWh)	607	414	414
Net electric power trade (thousand GWh)	205	382	367
Allowance price (\$)	98	-----	359
Total costs (billion \$)	101.42	96.89	96.96

The simulation results suggest that the actual configuration of generation, loads, electric power trade, and emissions may not be the most economically efficient. An overall optimization at the national level shows that there are opportunities to better utilize low cost coal-fired generators, curtailing usage of higher cost natural-gas units and increasing

electric power trade, which would ultimately allow customers to benefit from lower electricity prices.

B. Coal Network

The geographical distribution of the coal production for all cases is displayed in Fig. 3. This figure also shows the aggregated coal flows from the coal production nodes to the coal-fired generators obtained in case B. The width of the arcs is proportional to the flow, as identified in the legend. For clarity, the arcs with flow zero are not displayed. As shown, most of the coal flows from the Powder River Basin (PRB) node (the leading source of coal) into the Central and Midwestern parts of the country, where the majority of the coal-fired power plants are located. When electricity generation levels are not restricted to the actual values, i.e. when moving from the reference case A to cases B and C, the national coal production increases. In case B, coal production is intensified in the PRB and in the Northern Appalachian regions. With the emissions constraint imposed in case C, the Northern Appalachian coal production decreases and is compensated by an increase in Central Appalachian coal. Although the heat value is about the same for the coal extracted from these two regions, Central Appalachian coal is more expensive, but has lower sulfur content.

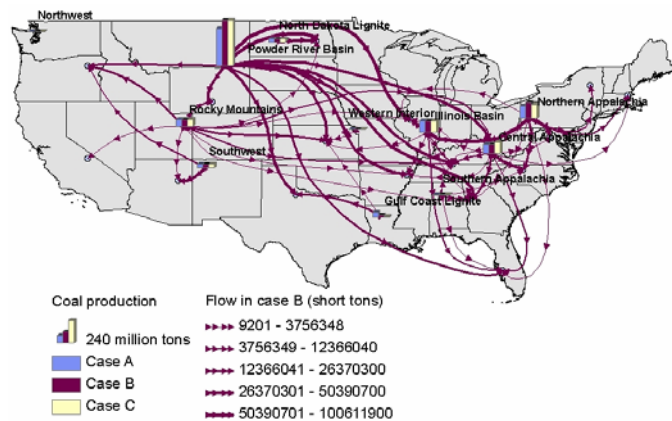


Fig. 3. Coal flows.

C. Natural Gas Network

Fig. 4 shows the natural gas flows observed in case B, along with the geographical distribution of the natural gas supplies for all cases, including national production and Canadian imports. As expected, most of the national production of natural gas comes from the Gulf of Mexico and the areas around Texas and the Rocky Mountains. When the electricity generation levels are not restricted to the actual values, natural gas supply decreases, as less expensive coal-fired generation is called on to displace pricier gas-fired generation. Although natural gas supplies decrease in the optimal cases B and C, imports into the Western, Midwest, and Northeast regions and transportation from the Southeast to the Northeast are heavily congested. Key pipeline capacity expansions should therefore target these corridors.

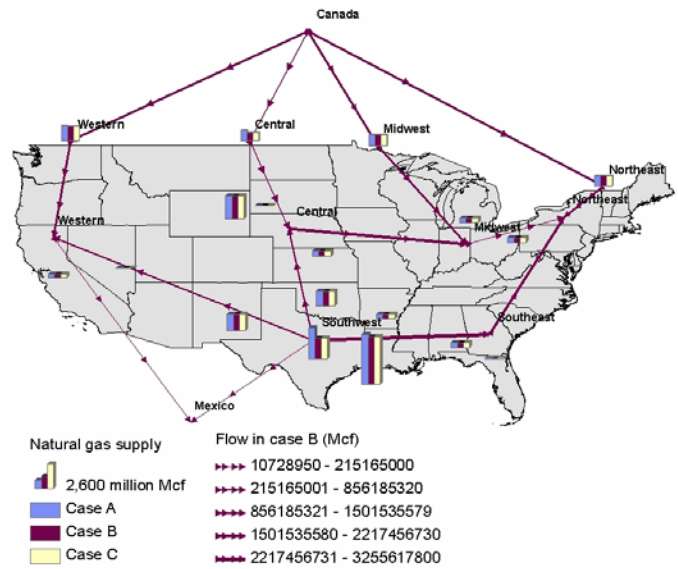


Fig. 4. Natural gas flows.

D. Electricity Network

The annual electricity generated from coal and natural gas plants are depicted in Fig. 5 and Fig. 6, respectively. In case B, electricity generated from coal-fired units increases across most regions. The most significant increases are observed in MAAC, ECAR, Entergy (EES), and MAIN. On the other hand, electricity generated from natural gas-fired units decreases significantly in almost all regions, except in ERCOT, where it remains the same, and NWPP and AZNM, where it actually increases. In some regions, namely MAPP, MAIN, ECAR, and MAAC, electricity generation from natural gas is completely eliminated, as a result of a strict merit order dispatch solution (low cost to high cost). Given the characteristics of combustion turbine units (fast start-up and high operating costs), some natural gas-fired units are often used as peaking-load generators. This means that they are needed to operate for a relatively small number of hours to meet peak demand requirements. Therefore, the fact that electricity generation from natural gas-fired units is reduced to zero in some regions may not be feasible. Nonetheless, given the potential cost savings that this would represent, it is an indication that utilities in these regions should pay careful attention to the design and implementation of demand side management (DSM) programs that would encourage consumers to modify their level and pattern of electricity usage. Effective DSM initiatives would contribute to the alleviation of peak loading conditions, thus reducing the need for peaking units and associated natural gas consumption. Besides this type of utility-administered programs, local governments and/or regulatory bodies could intervene by establishing energy efficiency standards, for example.

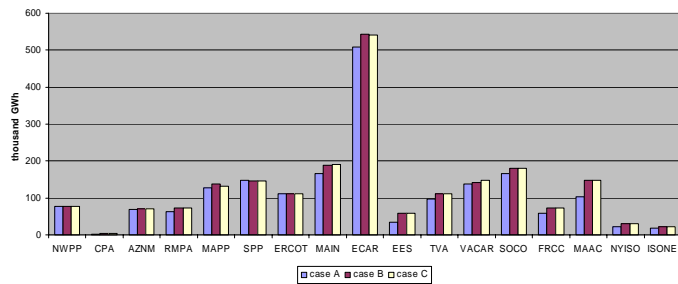


Fig. 5. Annual electricity generation from coal-fired units.

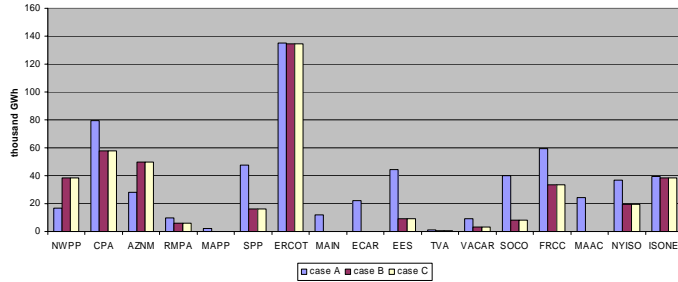


Fig. 6. Annual electricity generation from gas-fired units.

Fig. 7 shows the annual net interregional transfers of power for all regions. Positive values represent net sales and negative values correspond to net purchases. In the reference case, because generation and load levels are fixed at the actual values, electric power trade between regions corresponds to the actual operating levels. In most of the regions, net power trade increases in the optimal case B, when compared to the reference case A. With the introduction of the SO₂ emissions constraint, i.e. in case C, electric power trade slightly decreases. Fig. 7 also shows the electricity flows between regions obtained in case B.

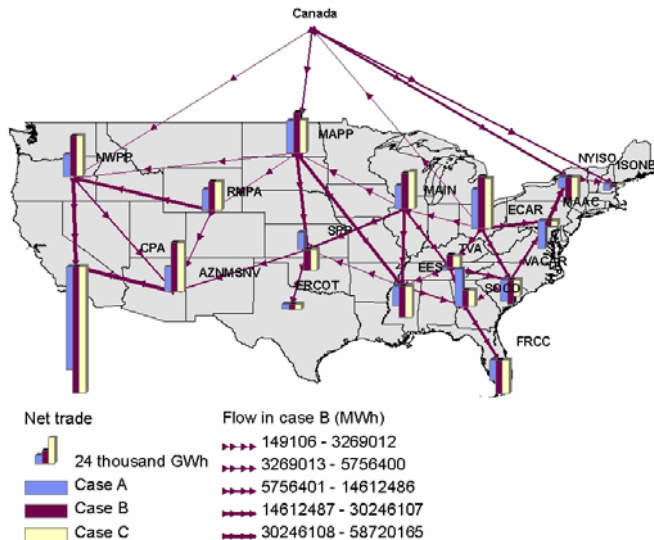


Fig. 7. Electric energy flows.

These results indicate that there may be opportunities to increase interregional electricity trade, with the associated economic benefits and environmental impacts, which are not being realized. Although there is very little literature on this matter, a recent study has identified imperfect information,

lags in the scheduling process, forecast errors, and risk avoidance as the main reasons that prevent an efficient electric energy trading activity [8]. In addition, some regions may not have incentive to increase generation levels for export to neighboring regions, resulting in a less optimal energy flow pattern. Imperfections in energy markets may lead to uncertainties in cost recovery, which would prevent utilities from allowing their own marginal cost to increase. These impediments to the efficient trading outcome are generally referred to as seams issues, because they arise at the borders of the ISOs or control areas.

Fig. 8 depicts the average nodal prices in each region. As expected, most of the nodal prices drop when the generation levels are not fixed, as a result of the smaller utilization of higher cost generation from natural gas. MAAC is the region that realizes the largest nodal price reduction. Nonetheless, nodal prices actually increase in some western regions, as more expensive supply resources are called on to displace even higher cost units in other regions. This means that the opportunity to reduce the national level total costs come at the expense of some regional nodal prices, which increase in both optimal cases B and C.

With the introduction of the environmental constraint, an increase of the lower nodal prices is observed. This reflects the utilization of more expensive and cleaner coal necessary to satisfy the emissions limit.

The northeast regions of NYISO and ISONE maintain the highest nodal prices, and the difference between MAAC and NYISO nodal prices is a clear indication of congestion. Likewise, the difference between the nodal prices in MAPP and the western and southern connected regions, and the difference between the nodal prices in SOCO and FRCC are also indications that cheaper generation cannot be exported to the higher priced regions, because the electric transmission capacity between the affected regions is fully utilized.

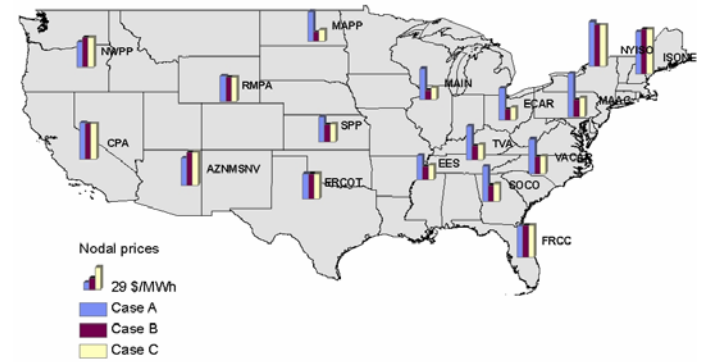


Fig. 8. Geographical distribution of the nodal prices.

As an example of the evolution of the nodal prices in time, Fig. 9 and Fig. 10 show the monthly nodal prices observed in the MAAC and NYISO regions, respectively. In the reference case A, nodal prices are always in the 50-60 \$/MWh range, in both regions. In the time interval from January to May and November to December the price differences between these two regions are very small and reflect the effect of transmission losses. However, the divergence observed

between June and October is a clear indication of congestion that prevents cheaper generation in the MAAC region to be exported to the higher priced NYISO region.

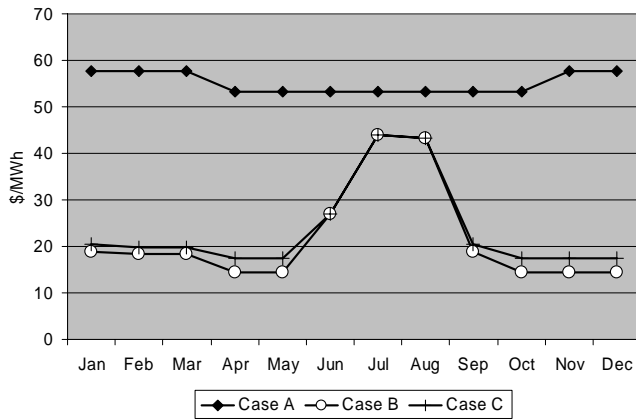


Fig. 9. Monthly nodal prices in the MAAC region.

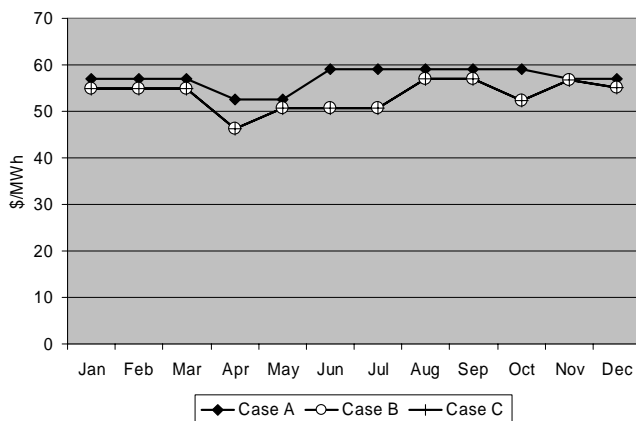


Fig. 10. Monthly nodal prices in the NYISO region.

For all months and in both regions, the nodal prices in the optimal cases B and C are below those observed in case A. This is particularly noticeable in the MAAC regions, where the more expensive electricity generation from natural gas is replaced by lower cost generation from coal. With increased electricity trade, nodal prices in the NYISO region are not able to match those in MAAC, because the transfer capability between regions is always fully utilized. Finally, it is interesting to note that there are no nodal price differences between cases B and C in the NYISO region, as the marginal unit used is always a gas-fired generator, and therefore unaffected by the emissions constraint imposed in case C. In the MAAC region, a small increase in the nodal prices is observed in the presence of the environmental constraint, which denotes the utilization of more expensive generators and/or more expensive fuels, in order to comply with emissions requirements.

The national level perspective indicates that an increase in trade would result in better utilization of low cost generators, curtailing usage of higher cost units and allowing customers to benefit from lower prices. Nonetheless, social benefits would be limited by the transmission system, inhibiting reduction in

price disparity between some regions.

E. Emissions

Fig. 11 presents the 2002 vintage allowances allocated to the modeled units, along with the emissions corresponding to the three analysis cases. Case A is configured with the actual emissions level of 9,446 thousand tons. In case B, emissions are not restricted, and in case C emissions are limited by the actual level and the constraint is binding. Although the aggregated level of emissions released in case A and case C are the same, their spatial distribution is different. In the optimal centralized decision making case (case C) the increased utilization of coal-fired units and associated increased electricity trade affect the spatial distribution of SO₂ emissions, by increasing concentration predominantly in the ECAR and MAAC regions. These regions are the ones that were already emitting the most above their initial allocation, taking advantage of the trading and banking mechanisms. These results show that, although trading of emissions allowances does not change the national aggregate emissions level set by the Clean Air Act Amendments (CAAA), it does tend to minimize the overall cost of compliance.

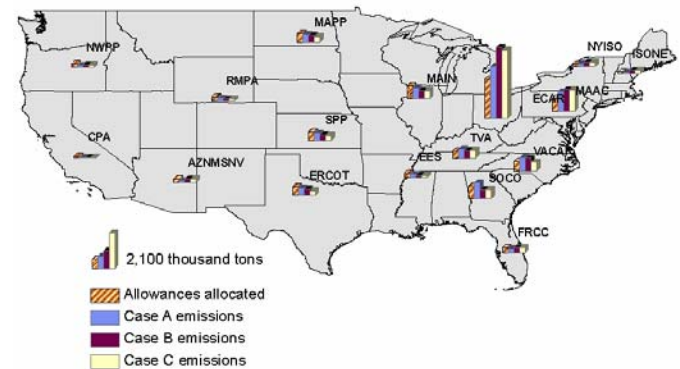


Fig. 11. Geographical distribution of SO₂ emissions.

Some environmentalists and critics of the cap and trade program have raised concerns about its environmental integrity, suggesting that this trading mechanism may lead to the creation of geographic hotspots (localized areas where the amount of pollutant deposited actually increases, as a result of the fact that polluting sources are not uniformly mixed in space) [9], [10]. Nonetheless, empirical studies that analyze state and regional flows in allowance trading show that the SO₂ allowance trading program has not led to regional concentration of emissions [11]-[13]. Rather, the authors of these studies argue that the program is helping cut concentrations since the largest sources are those that have reduced emissions the most, smoothing out emissions concentrations instead of concentrating them. This is usually referred to a cooling effect whereby the greatest reductions are in the areas most adversely affected historically. In addition, massive reductions in aggregate emissions accomplished under the CAAA should enable an overall welfare benefit that far outweighs incidental hotspot activity.

V. ALTERNATIVE ENERGY TRANSPORTATION MODES

Decisions to buy or sell bulk electrical energy are typically made without significant consideration of using alternative energy transportation modes, that is, using railroads or barges for coal and pipelines for gas instead of electric transmission for electricity. Likewise, decisions to buy or sell coal or gas are typically made without significant consideration of alternative energy transportation using electric transmission. Clearly, there are a large number of feasible alternatives to satisfy electricity demands, and the most economic alternative varies with fuel production, transportation availability, environmental regulations, and prices.

The integrated energy system model presented in this two-part paper is suitable to investigate the tradeoffs between alternative energy transportation modes. While a number of studies have compared AC and DC electric transmission, only one study was found in the literature to compare the costs and environmental impacts of different transporting modes and associated energy forms [14]. This study analyzed two options for transporting energy from the PRB to Dallas: (1) in the form of coal, by rail and (2) in the form of electricity, by transmission lines. The results of this study are however very dependant on the assumptions made (e.g., capital costs needed to build new transmission, while existing railroad bed was assumed to have sufficient capacity to accommodate the increased traffic), which makes them very site-specific and difficult to generalize for the North-American system.

To illustrate the application of the integrated energy system model to analyze the substitutability of the different energy transportation options, we implemented the configuration with fixed coal production levels and unconstrained coal-fired electricity generation. Comparing with case A, total costs decrease from \$ 101.42 billion to \$ 101.20 billion. This cost reduction indicates that the energy movements from the coal mines to the electric load centers in case A were not optimal. It is possible to observe significant shifts between coal transportation and electric transmission. Given the modeling assumptions and methodology described in [1], the simulation results suggest that more energy should be transported from the Appalachian mines to the consuming regions in the Northeast in the form of coal, and less in the form of electric transmission. Likewise, it would have been more efficient if electricity generators in regions such as MAPP, SPP, and MAIN consumed less coal and exported less electricity, as western coal from the PRB and the Rockies would have been shipped further east.

In summary, for the same coal production levels in each coal supply node, the model results indicate that there are some efficiency losses in the coal by wire option.

VI. DIRECTIONS FOR FUTURE WORK

The conclusions available from the analysis described raise interesting issues for a more complete version of the model, and suggest exciting areas of further research. Future work should focus on aspects such as improving data quality and

quantity, incorporating uncertainties about certain data parameters, representing the interactions between the physical system and markets, and accounting for the influence of perceived future conditions.

A. Data Quality and Quantity

Many of the assumptions and modeling choices that have been made are the result of data limitations. A more complete and accurate set of data would facilitate a more comprehensive analysis of the opportunities for additional economic efficiencies than does the high level representation that has been analyzed. In addition, a more detailed portrayal of the integrated energy system would allow a more descriptive type of validation and result in findings with higher confidence levels. For example, one of the critical assumptions associated with the aggregated level that has been chosen is that electricity flows within each demand region are unconstrained. However, the effects of intraregional congestion, if known, could be introduced indirectly into the model by appropriately calibrating/derating the interregional transfer capabilities.

B. Uncertainties

This two-part paper has proposed a deterministic model of the integrated energy system. The real circumstances in which decisions are made are however characterized by imperfect information about data, namely electricity demands and fuel prices, which justify extending the linear programming methodology that has been presented to a stochastic optimization model. A stochastic optimization problem formulation would enable handling uncertain data, given probabilistic information on the random quantities.

C. Market Rules

The dynamics of the fuels, electricity, and emissions markets can interact with the physical system in ways that significantly affect system operations. A possible extension to this work would be to incorporate the associated market rules and assess their interplays with the structural aspects of the integrated energy system. This would allow the evaluation of how modifications in current market designs could affect the energy flows and the overall economic performance of the integrated energy system.

D. Perceived Future Conditions

Current expectations of future conditions are an integral part of real-world judgment and decision-making processes. For example, the allowance price derived by the model does not capture the fact that an expected rise in natural gas prices creates an incentive to increase SO₂ allowances price, as the opportunity of fuel switching is perceived to be less attractive. The task of capturing the real-world decision processes and the complex dynamics of management behavior (as opposed to a purely physical model) could be accomplished by establishing feedback loops between the appropriate decision points, to make explicit causal relationships among the various components of the integrated energy system.

VII. MODEL APPLICATIONS

The model developed can be used in supporting a wider range of public and private decisions related to the energy sector, providing explicit national and regional evaluation of the impact of different events, policies, and infrastructure enhancements on electric energy prices and price variability. Examples of issues that can potentially be addressed by the integrated energy model are provided in the following.

A. Electricity Industry Issues

- What are the most important issues inhibiting the ability to transact electric power across control area boundaries?
- How would increased transmission capability influence wholesale electricity prices?
- How would major investment in a specific electricity national or regional generation portfolio affect electricity prices?
- What are the potential peak demand reductions and energy savings accrued from DSM programs?

B. Fuel Markets Issues

- How do high natural gas prices impact the coal industry?
- How would a major disruption in the coal industry, affecting either coal production levels (e.g., a coal miners strike) or coal deliverability (e.g., a coal train derailment), impact the generation mix?
- How would increases in coal exports (namely to fast developing economies such as China) affect domestic coal markets?

C. Air Emissions Issues

- How will tighter emissions limits affect SO₂ prices and compliance decisions?
- How would different banking strategies affect SO₂ prices and compliance decisions?
- How would the aggregate level of emissions and their geographical distribution change if states imposed local standards or trading restrictions? What would be the impacts on the fuel and electricity markets?
- How do high natural gas prices drive emissions prices?
- How would CO₂ regulations impact the coal, gas, electricity, and SO₂ markets?

VIII. CONCLUSIONS

The developed model is a simulation tool that helps build a basic understanding of the complex dynamics of the integrated energy system. It enables energy companies to carry out comprehensive analyses of their investments as well as overall optimization of their energy supply alternatives. Governmental bodies may also utilize the developed techniques to do comprehensive scenario studies with respect to environmental impacts and consequences of different regulating regimes. In summary, an important impact of the work is to motivate the key decision makers (e.g., generation owners, fuel suppliers, governmental agencies, etc.) to create the necessary conditions and incentive mechanisms so that

more efficient flow patterns are utilized by overcoming informational, organizational, regulatory, and/or political barriers, by increasing link or production capacity, or by building new links or production facilities.

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