Industry Sensitivity to Extreme Price Scenarios in a Stochastic Energy Model

Brian K. Boyd, Joseph M. Roop, and Olga V. Livingston, Pacific Northwest National Laboratory[a]

ABSTRACT

The Stochastic Energy Deployment System (SEDS) is a full characterization model of the U.S. energy economy, including various demand sectors and the electricity, liquid fuels, natural gas, coal and renewable energy sectors. SEDS was developed by a consortium of national laboratories, including Argonne National Laboratory (ANL), Oak Ridge National Laboratory (ORNL), the National Renewable Energy Laboratory (NREL), Pacific Northwest National Laboratory (PNNL), Lawrence Berkeley National Laboratory (LBNL), and the National Energy Technology Laboratory (NETL). The SEDS model is designed to look both deterministically and stochastically at the effects of extreme price scenarios demonstrating market penetration of new technologies and fuel switching. While it is not meant to be a competitor of the National Energy Modeling System (NEMS), it does do what NEMS cannot do – look at the probability distributions around key parameters and variables, such as the effects of primary fuel source pricing, fuel switching and technology penetration.

The industrial sector is modeled using the Manufacturing Energy Consumption Survey's (MECS) end-use detail as a starting point, with auxiliary energy requirements for compression, pumping, air displacement, conveyance, motor drive, etc., derived from the modeling system developed at PNNL and Simon Fraser University. The major end uses – process heat, electrochemical processes, cooling and refrigeration, and other process requirements – are calibrated to MECS data for both the total of end uses and for specific fuels and then simulated and benchmarked to the Annual Energy Outlook (AEO) 2010 reference case. The paper presents results of the integrated model under extreme pricing scenarios for the primary fuel sources used in the industrial sector.

Introduction

A new energy model is being developed by the Department of Energy's Energy Efficiency and Renewable Energy Office. The model is structured such that it is responsive to changes in fuel prices and is capable of accommodating multi-fuel technologies. Simulations were performed on the integrated model to investigate behavior of the industrial sector under extreme price scenarios. Analyzed outputs illustrate fuel demand, fuel switching characteristics, CO_2 from on-site combustion, CO_2 from all consumed energy, and fuel intensity of the industrial sector. This paper will describe the industrial sector of SEDS, show how supply pricing is incorporated and demonstrate industries' sensitivity to extreme price scenarios projected through 2030.

---

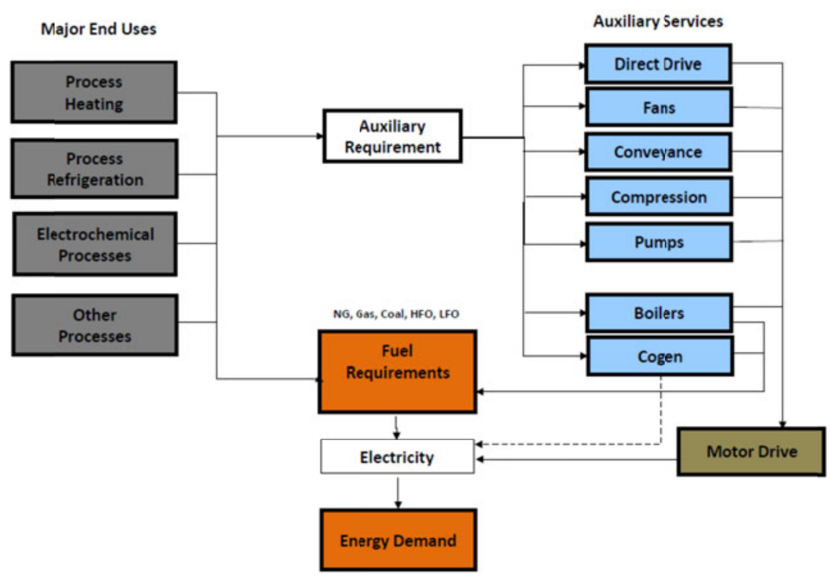
[a] Operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC05-76RL0 1830.

Model Structure

This industrial model is primarily an aggregate representation of the U.S. manufacturing sector. It is a typical engineering-economic model of the industrial sector with output, energy use and technology stocks calibrated to the 2006 Manufacturing Energy Consumption Survey's (MECS) data, then simulated and benchmarked to the 2010 Annual Energy Outlook (AEO). The outputs calculated by the module are energy requirements by fuel type, byproduct gas price, emissions, capital and energy expenditures, as well as the overall sector energy intensity metric.

The industrial sector energy consumption is tied explicitly to output produced and the technologies used to produce that output. The module structure is illustrated in Figure 1. The industrial sector module is initialized based on the manufacturing output, which is attributed proportionally to the four major end uses: process heating, process refrigeration, electrochemical processes and other processes. These primary processes have two sets of requirements: a) direct fuel and b) auxiliary services. The latter group requires shaft drive provided by motors of different size classes and efficiencies. Auxiliary requirement coefficients and technological splits for size classes are derived from the Canadian Integrated Modeling System CIMS-US model.

Figure 1. Industrial Model Structure

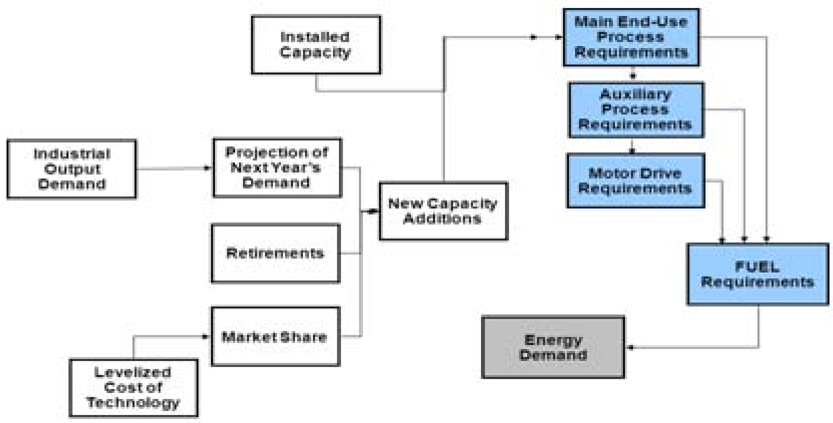


Primary processes reflected in the model are gross representations of averages of equipment contained in the CIMS data base, but themselves have no real-world technology equivalent. While the major end-use modules are not strictly technologies, the auxiliary services that are required by these major end-use modules are. Major auxiliary services in the module include pumps, fans, compressors, conveyors, motors, lighting, boilers and cogeneration.

After direct and indirect energy use is accounted for, the subtotal demand for electricity is lowered by the cogeneration amount. Thus, the total energy demand represents the net quantity of the purchased energy rather than overall energy consumed by the industrial sector. This leads to a CO_2 emissions calculation that is determined by the carbon content of each fuel and the amount of fuel combusted. The difference between MECS data and AEO totals was included in the module as non-manufacturing fuel use.

The main driver for the module is manufacturing output growth. Industrial sector equipment stock meeting each of the end uses is tracked in the output equivalent. After initial output is proportionately assigned to the major end-use submodules, the model simulates from the calibration year onward by forecasting the output quantity based on the manufacturing growth rate. Industrial stock flow logic is depicted in Figure 2.

Figure 2. Industrial Sector Stock Flow



Separate vintages of stock are tracked, so that each vintage retires subject to its expected economic life. To meet the output projection, the model adjusts the current stock for retirements and then calculates necessary new capacity additions.

New stock is purchased using a market share calculation that compares different efficiencies of stock and levelized cost. Capital costs, fixed and variable operation and maintenance (O&M) costs, emissions costs, tax incentives, and the expected utilization rates are used to calculate the levelized annual total cost for each technology. Fuel costs, which depend on the rate at which the fuel is used and the price of fuels, are included as well. Capital costs can be decreased by research and development (R&D) and learning curve. The effects of R&D are treated with uncertainty and can be adjusted to try to capture the level of government investment in R&D. Improvements from learning-by-doing are based on cumulative installed capacity, such that a specified percent improvement in capital costs is achieved for each doubling of capacity. Production tax credits, investment tax credits, and accelerated depreciation can be applied to appropriate technologies and will lead to lower levelized annual costs. The combination of all these factors produces a levelized annual cost that is used to determine how the market share of new capacity additions will be given to the competing technologies.

There are three generations of technologies that compete for new stock additions: current, state-of-the-art and advanced. Current generation captures the technologies that are available now and will not be competing for new share additions after 2015. This generation has lower levelized capital cost, but high fuel intensities. The state-of-the-art is competitive with the current stock immediately; the advanced technology becomes competitive with these two in 2025. The state-of-the-art and advanced technologies have higher capital cost and a lower fuel requirement.

Multiple fuel options, such as natural gas, electricity, coal, light fuel oil, heavy fuel oil and byproduct gas, are included for each of the technology types where fuel substitution is appropriate. The structure is such that process heating uses electricity, coal, natural gas and byproduct gas with only a very minor portion serviced by light fuel oil. Process refrigeration and cooling uses either electricity or natural gas absorption cooling. The electro-chemical processes are dominated by electricity use. Other processes, a general category that accounts for primary processes not included in the previous three categories, is serviced by coal, natural gas, electricity and byproduct gas, with a small fraction using light fuel oil.

Just like the end-use service equipment, auxiliary services compete on the basis of costs to satisfy requirements needed by the major end-use services for the production of manufacturing goods. Capital costs, operating and maintenance costs, and performance characteristics for all the auxiliary equipment are drawn from the CIMS-US data base, and are currently being updated.

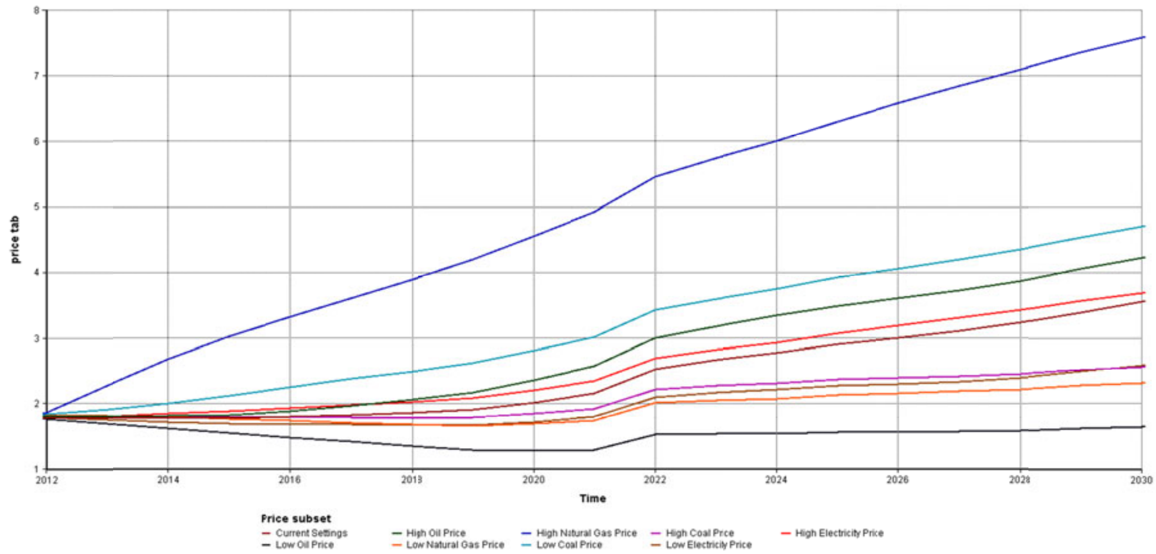
Extreme Price Results

Simulations were performed on the integrated model to investigate behavior of the industrial sector under extreme price scenarios. Analyzed outputs are fuel demand, fuel cost interactions of the industrial sector, and CO_2 production from all consumed energy. Although low and high price scenarios can be evaluated for all fuel types, only results for coal, natural gas, oil, and electricity are illustrated here.

Fuel Demand

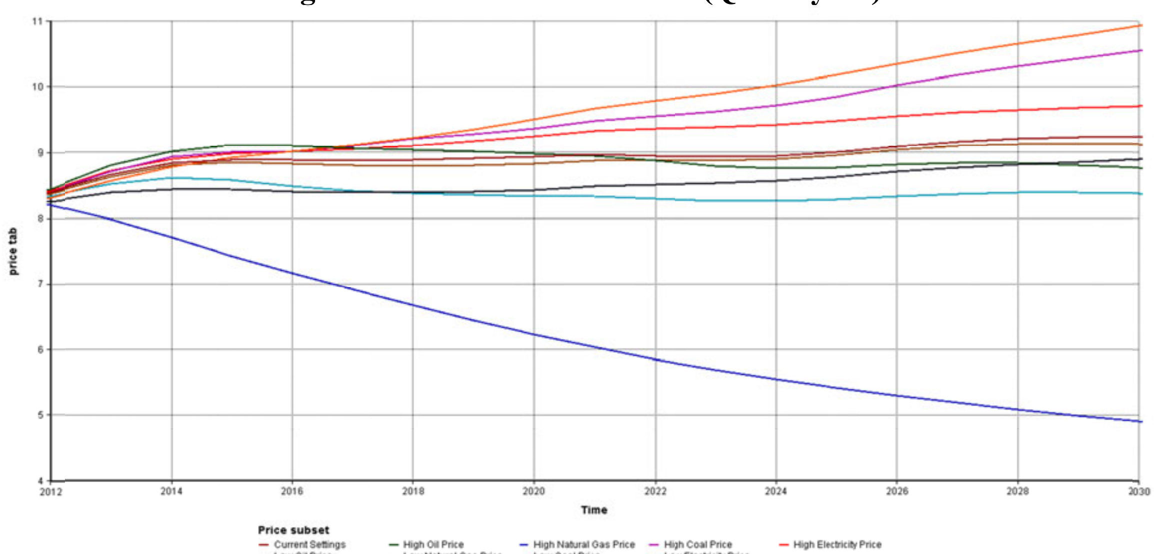
Coal demand (Figure 3) increases most significantly in the industrial sector when natural gas prices are high followed by low coal price scenarios. This demonstrates preferential fuel switching in industry is between coal and natural gas, where high natural gas prices result in steady expansion of coal consuming technologies. Coal demand rises to a lesser extent for all the other scenarios, except when oil prices are low, where coal demand is slightly lower in 2030 than in 2011. This is because of expansion of byproduct gas production in a low cost oil scenario and the penetration of technologies consuming byproduct gas rather than coal in the industrial sector.

Figure 3. Coal Demand (Quads/year)



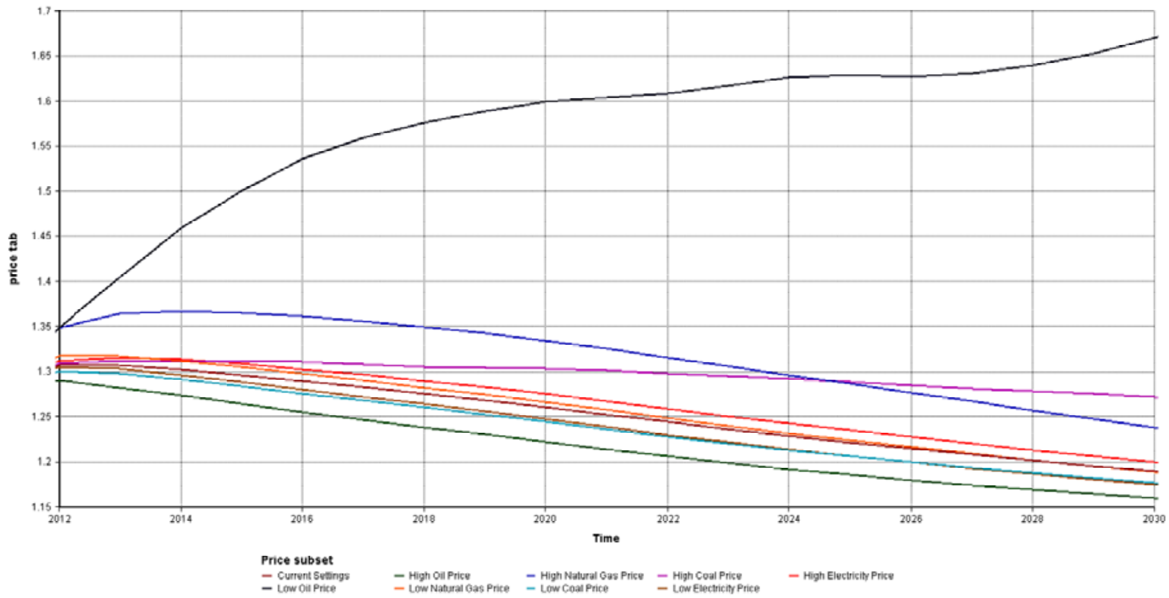
Natural gas demand (Figure 4) rises steadily for most extreme pricing scenarios, but most significantly when natural gas prices are low. Further, natural gas demand is reduced from over 8 quads/year to less than 5 quads/year when natural gas prices are extremely high. This demonstrates primary dependence on its own price followed to a lesser extent by extreme coal price scenarios.

Figure 4. Natural Gas Demand (Quads/year)



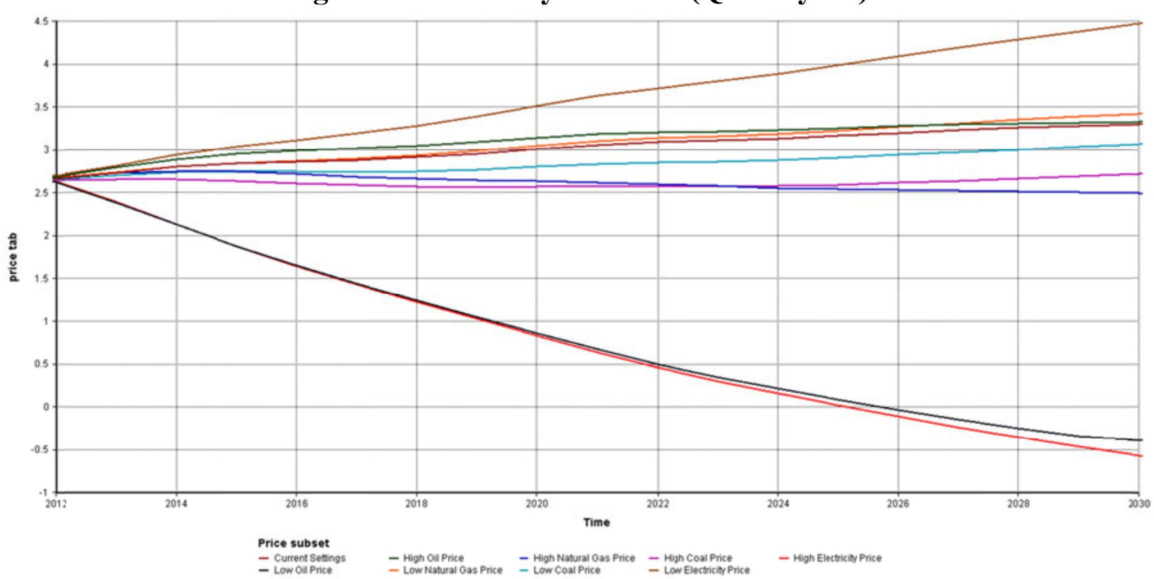
Oil demand (Figure 5) is reduced for every extreme pricing scenario except when oil prices are low. Growth from 2011 to 2030 in this scenario rises from 1.35 quads/year to 1.65 quads/year. The most significant reduction occurs when oil prices are extremely high, dropping demand from 1.3 quads/year to 1.15 quads/year.

Figure 5. Oil Demand (Quads/year)



Electricity demand (Figure 6) rises from 2.6 quads/year to 4.5 quads/year when electricity costs are low. Electricity demand drops precipitously in the industrial sector when electricity prices are extremely high or oil prices are extremely low. Byproduct gas production rapidly increases in the low oil price condition replacing electricity demand, while high electricity prices lead to expanded penetration of cogeneration.

Figure 6. Electricity Demand (Quads/year)

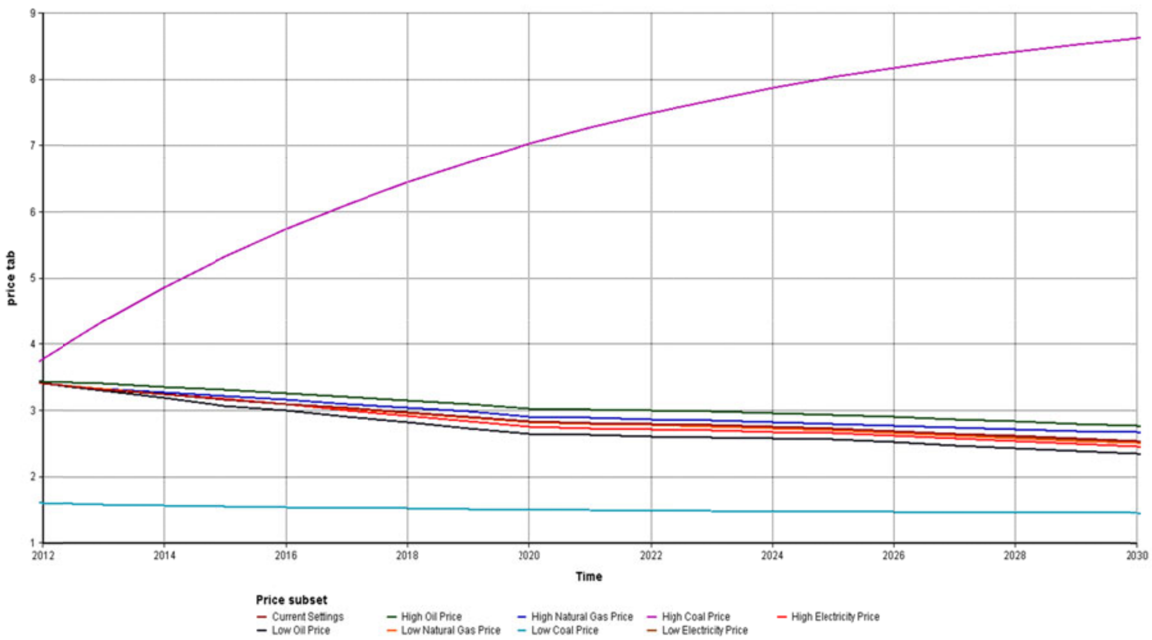


Fuel Cost Interactions

Fuel costs for extreme high pricing in each case are elevated in the near term and then stabilized over time. It is important to note the inter-dependence of each fuel source and fuel switching impacts within the model. For each resource the trends are bounded by respective high and low costs illustrating the pricing used for this analysis. In each case, the trends also demonstrate price sensitivity to the other resources under extremely high and extremely low pricing scenarios.

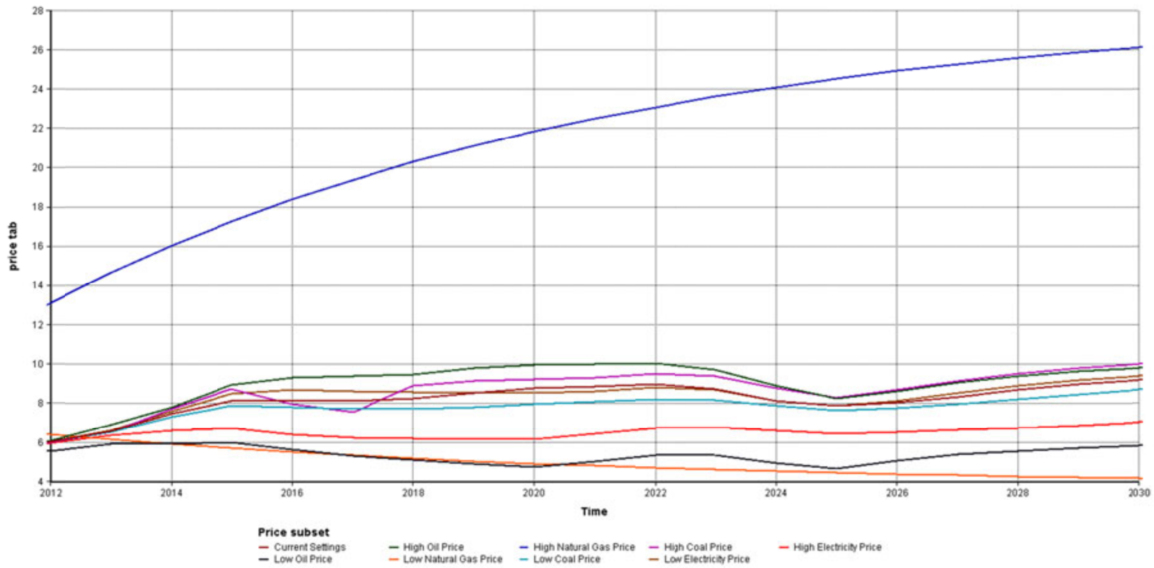
Coal costs (Figure 7) are bounded by high and low coal pricing conditions, with high prices ramping from $3.80/GJ to $7.00/GJ in 2020 and then stabilized to a peak price of $8.60/GJ in 2030. On the opposite end, low coal prices are held to $0.50/GJ over the duration. The remaining trends show coal costs reducing slightly regardless of high and low cost scenarios for natural gas, electricity, and oil. The results illustrate the model's ability for fuel switching and technology penetration to offset extreme high pricing from any one of the other fuel sources.

Figure 7. Industrial Coal Prices (2009$/GJ)



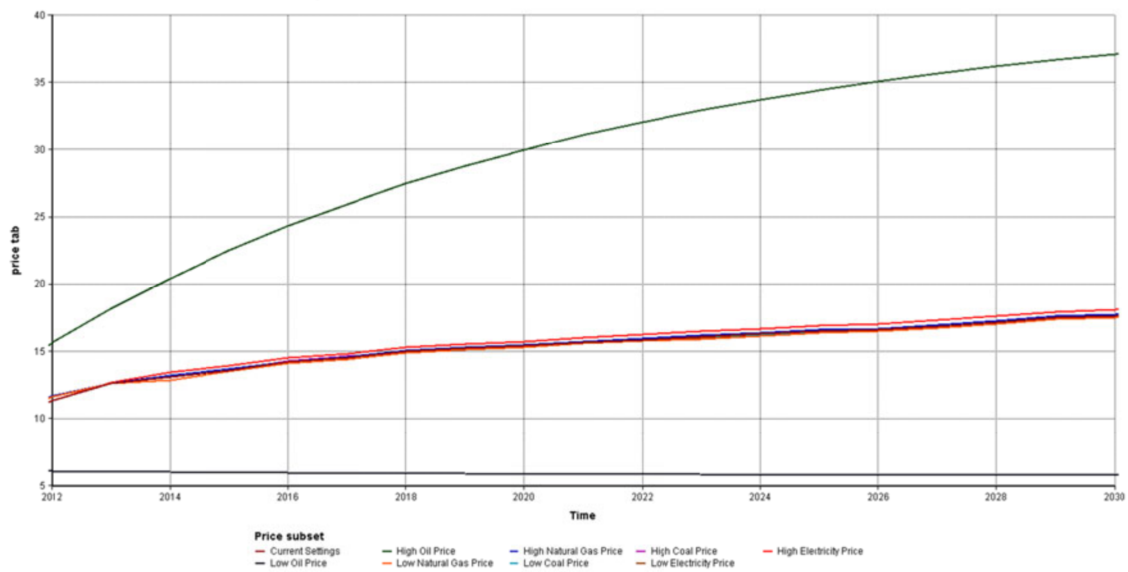
Natural gas costs (Figure 8) illustrate the extreme high pricing growing from $13.00/GJ to $22.00/GJ in 2020, followed by less aggressive growth to $26.00/GJ in 2030. Extremely low pricing for natural gas starts at $6.50/GJ in 2011 and drops steadily to $4.25/GJ in 2030. Natural gas prices in the industrial sector behave similarly for all other pricing scenarios rising slightly because of high and low coal pricing, as well as high oil low electricity prices. High electricity and low oil pricing scenarios result in stable natural gas prices over the duration.

Figure 8. Industrial Natural Gas Prices (2009$/GJ)



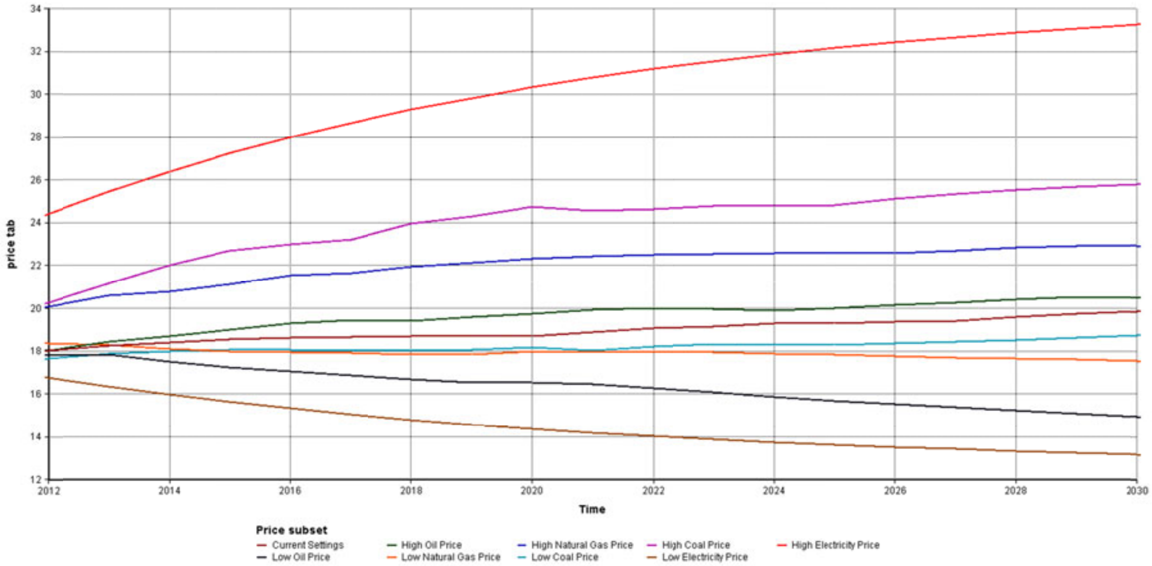
Oil costs (Figure 9) illustrate high pricing starting at $15.00/GJ in 2011 with aggressive growth to $30.00/GJ in 2020, followed by stabilized growth to $37.00/GJ in 2030. Extremely low prices are held stable at $6.00/GJ for the duration. Oil pricing displays the least variability against the other fuel sources with prices starting at $12.00/GJ and ending at $15.00/GJ regardless of the fuel pricing scenario.

Figure 9. Industrial Oil Prices (2009$/GJ)



Electricity costs (Figure 10) have the largest spread of all the fuel sources analyzed. High and low electricity costs frame the trends, with high costs starting at $24.00/GJ in 2011 and growing rapidly to $30.50/GJ in 2020, followed by less aggressive growth to $33.00/GJ in 2030. Low electricity prices drop steadily over the 20-year model period from $17.00/GJ to $13.00/GJ. Prices rise when coal prices and natural gas prices are elevated because of the dependence of electricity generation on these two resources, and prices are reduced when oil prices are extremely low because of the production of byproduct gas.

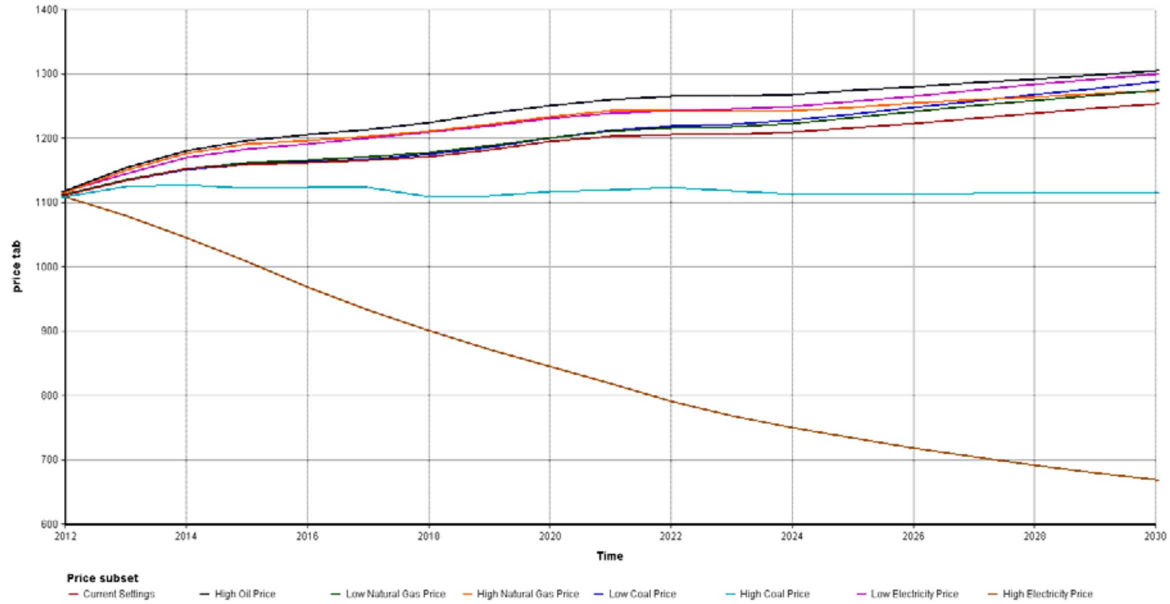
Figure 10. Industrial Electricity Prices (2009$/GJ)



Carbon Emissions

Carbon emission impacts (Figure 11) for these pricing scenarios show CO_2 levels elevating for each pricing condition except for high coal prices, where CO_2 emissions are relatively level from 2011 through 2030. Growth from the majority of the pricing scenarios is on the order of 200 $MMtCO_2$ over the 20-year time period. The lone scenario where CO_2 emissions decrease over time based on extreme pricing occurs when electricity costs are excessively high. In this case, CO_2 reductions can be attributed to changes in the electric generating sector where renewable resources and carbon capture technologies become cost-effective. Additionally, the industrial sector reacts by expanding cogeneration to supply its own electrical needs.

Figure 11. CO_2 Emissions ($MMtCO_2$)



Conclusion

Full characterization models of the U.S. energy economy afford the opportunity to simulate the implications of carbon policy, market penetration of new technologies, and the effect of resource price scenarios. The SEDS industrial sector model is capable of analyzing these different scenarios both deterministically and stochastically. In the context of the fully integrated model, the results presented here came from simulations to the industrial sector for high and low extreme pricing scenarios for primary fuel resources – specifically oil, natural gas, coal, and electricity.

The results demonstrate the inter-dependence of each fuel source, fuel switching impacts, and technology penetration within the model. Demand trends reveal rapid expansion of coal use should natural gas prices become excessively high, increased natural gas demand unless coal prices are extremely low or natural prices become elevated, reduced oil demand except when oil prices are low, increased electricity demand when electricity prices are low, and decreased electricity demand when electricity prices are high or oil prices become excessively low. Low oil prices result in reduced electricity consumption in the industrial sector because byproduct gas production expands and replaces electricity in multiple primary process applications. Price sensitivity shows coal and oil are the least responsive to extreme pricing for the other resources, while electricity prices experience the largest variation when the other resources are excessively expensive or inexpensive. Finally, industry CO_2 emissions rise for every scenario except for high coal prices and high electricity prices. The latter case is the only pricing scenario resulting in reduced CO_2 emissions because of changes in the electric generation sector and expansion of cogeneration in industry.

References

Analytica Professional 4.2 by Lumina Decisions Systems, Inc. February 2010.

Bataille, Christ G.F. 2005 Design and Application of a Technologically Explicit Hybrid Energy-Economy Policy Model with Micro and Macroeconomics Dynamics; School of Resources and Environmental Management, PhD theses, Simon Fraser University, British Columbia, Canada.

Browne, Marilyn A. et al. 1998. Engineering-Economic Studies of Energy Technologies to Reduce Greenhouse Gas Emissions: Opportunities and Challenges. Annual Review of Energy and Environment, 23: 287-385

Canadian Integrated Modeling System (CIMS), 2008. Energy and Materials Research Group, Simon Fraser University, British Columbia, Canada.

Cohendet, P. 1997. Evaluating the Industrial Indirect Effects of Technology Programmes: the Case of the European Space Agency (ESA) Programmes. Proceedings of the OECD Conference "Policy Evaluation in Innovation and Technology", B.E.T.A, Université Louis Pasteur, Strasbourg, France. Available on-line http://www.oecd.org/dataoecd/3/37/1822844.pdf

Jaccard, M. and J. Nyboer. 1992. ISTUM-PC User Guide, Vol 1, Model Description. Simon Fraser University, Vancouver, Canada

Livingston, Olga V., J.M. Roop and B.K. Boyd. 2010. Impact of Carbon Policy on Industry Use of Coal, Natural Gas and Electricity in a Stochastic Energy Model. 29th USAEE/IAEE North America conference, October 2010, 29th USAEE/IAEE Conference Proceedings, Calgary, Alberta, Canada. Pacific Northwest National Laboratory, Richland, Washington.

McFarland, J.R., J.M. Reilly and H.J.Herzog 2004. Representing energy technologies in top-down economic models using bottom-up information. Energy Economics, 26: 685-707

Rivers, Nic, and Mark Jaccard 2005. Combining Top-Down and Bottom-Up Approaches to Energy-Economy Modeling Using Discrete Choice Models. The Energy Journal, 26(1): 83 – 106

Train, Kenneth E. 2003. Discrete Choice Methods with Simulation. Cambridge University Press, Cambridge, Massachusetts.

U.S. Energy Information Administration. 2010. Annual Energy Outlook, Reference Case 2010. May 11, 2010. Washington, D.C.

U.S. Energy Information Administration, Manufacturing Energy Consumption Survey. 2006. Table 10.10, Release of June 2009, Washington, D.C.

U.S. Energy Information Administration, National Energy Modeling System. May 2010. Washington, D.C.

Worrel, Ernst, Stephan Ramesohl and Gale Boyd. 2004. Advances in Energy Forecasting Models Based on Engineering Economics. Annual Review of Environment and Resources, 29: 345-381