



Analysis of Power System Operational Risks from Gas System Dependence

Final Project Report

M-36

Power Systems Engineering Research Center
*Empowering Minds to Engineer
the Future Electric Energy System*



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Power Systems Engineering Research Center

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Executive Summary

Electricity generation increasingly relies on natural gas as older units are retired, because of the usually low fuel costs, considerably lower CO₂ emissions and the capability of gas-fired units to start up, shut down or change generation levels quickly. The fast response provides needed grid operational flexibility in systems with deep penetration of integrated renewable resources. The amount of electricity generated from natural gas has overtaken that generated from coal and is expected to continue its steady increase over the next three decades.

While there are sound reasons for increasing the proportion of electricity produced from natural gas, there are also hazards. Unlike other primary sources of energy used for electricity generation, gas also is used directly to meet other energy needs. Because gas used for other sectors has historically exceeded that used for electric power, the gas markets and delivery infrastructure have developed primarily to serve the needs of those other consumers. As a result, the timing of electricity and gas markets is not well coordinated, despite the changes made in response to FERC Order 809. In addition, electric power generators often procure gas under interruptible contracts. In contrast, industrial and commercial users, as well as the local distribution companies that provide gas to residential users, typically have firm transportation contracts for gas and thus receive higher priority for delivery when gas supplies are constrained. This combination of conditions creates economic risks for both gas generators and system operators. When the availability of contracted gas is limited, the gas generators may have to obtain fuel at high spot prices or switch to alternate fuels. The system operators may take various actions such as redispatching resources or importing power, which result in high wholesale electricity prices.

This project addressed two main issues related to the impacts on the power system of the uncertainty associated with natural gas supply and cost. The first issue is risk assessment and the second issue concerns the evaluation of alternative methods to mitigate the risk. A secondary issue of limited availability of public data on the gas system was addressed by providing a guide to such data that exist.

To assess the economic risk we approximate the probability distribution for the electric energy purchase costs to meet the forecast demand for electric energy over a time horizon of several hours to a day. First we cluster historical days based on weather and estimate the joint distributions of electric load and gas spot price in each cluster. We investigate the impact of uncertainty in the spot price of gas by conducting Monte Carlo simulations of hourly economic dispatch in two cases while systematically varying the amount of contracted gas available. In the first case, only load values are randomly sampled while the gas price is fixed at its mean value. In the second case, both input parameters are randomly sampled from their joint distribution. The simulation results confirm the experience of higher and more variable electric energy purchase costs when gas supply constraints combine with high spot prices. The risk is quantified in terms of metrics for the difference between the purchase cost distributions generated with and without gas price uncertainty.

We demonstrate how such risk quantification metrics can be used to evaluate alternative risk-mitigation strategies at the system level. In a numerical case study we find that an investment in

increased gas storage capacity reduces the risk more than an equal dollar investment in conversion to dual-fuel capability.

We also propose and analyze an alternative contractual arrangement under which a gas-fired generator could procure fuel in partnership with an industrial gas consumer. The basic concept of the proposed contract is for the gas-fired generator to sign a firm transportation contract and to resell any unused transportation to another gas customer whose gas demand may be more flexible. Such a contract can benefit both the gas generator and the industrial customer in the following ways. The gas-fired generator can benefit from the contract whenever its revenues under firm gas transportation exceed the additional costs of such service. As an example, the gas-fired generator may be dispatched under conditions of gas scarce transportation. Also, in certain situations, the generator may receive incentives to acquire firm transportation. The industrial customer can benefit from the contract if the surplus transportation purchased from the gas-fired generator is below the costs to handle intermittent supply situations that are due to non-firm transportation service. Typically, the resold transportation price is below the firm price paid by the gas generator and so is less than the interruptible transportation price that the industrial customer would otherwise face. Our analysis shows that the generator's load factor plays a key role in the determination of the firm contract costs. We conduct a wide range of simulations based on historical data to evaluate the profit outcomes of a large combined-cycle generator and a small combined-cycle turbine. Under the assumed conditions, the generators are able to acquire firm gas transportation and remain making a profit and in certain conditions the large generator obtains a much higher profit than under an interruptible contract.

Further investigation and additional testing would be required to produce specific recommendations for either system operators or gas-fired generators. For the system-wide study, our Monte Carlo simulations were conducted on a synthetic data set for the electric grid and gas system. System operators could combine actual data for their own systems with information on the pipeline network that serves their market participants and follow our procedure for risk quantification. Our proposed scheme for comparing alternative risk-mitigation strategies based on those risk quantification metrics should be tested more thoroughly under a variety of conditions, while considering possible combinations of investments. The dispatch model could be modified to represent some gas generators as having firm contracts for gas delivery while others rely on interruptible contracts, and the choice to enter into firm contracts could be evaluated as another risk-mitigation strategy. Future work on the proposed gas contract includes the construction of a more detailed representation of the cost elements related to pipeline operations and the modeling of gas nomination cycles in addition to the timely, day-ahead cycle. In addition, the incorporation of the proposed contract in a detailed, stochastic process-based production costing tool to evaluate the benefits that a gas-fired generator may obtain with and without the proposed contract could provide valuable insights on the effective deployment of the contract.

Project Publication:

- [1] D. Hu and S. M. Ryan, "Quantifying the Effect of Natural Gas Price Uncertainty on Economic Dispatch Cost Uncertainty," in *IEEE Power and Energy Society General Meeting*, Chicago, July 2017.

Student Theses:

- [1] Dan Hu. *Short Term Operation of Power Systems Considering the Natural Gas Network under Uncertainty*. Ph.D. Dissertation, Iowa State University, May 2019 (expected).
- [2] Adriano Lima Abrantes. *Analysis and Proposal of Grid Operational Flexibility Metrics for Bulk Power Systems*. Ph.D. Dissertation, University of Illinois at Urbana-Champaign, May 2019 (expected).