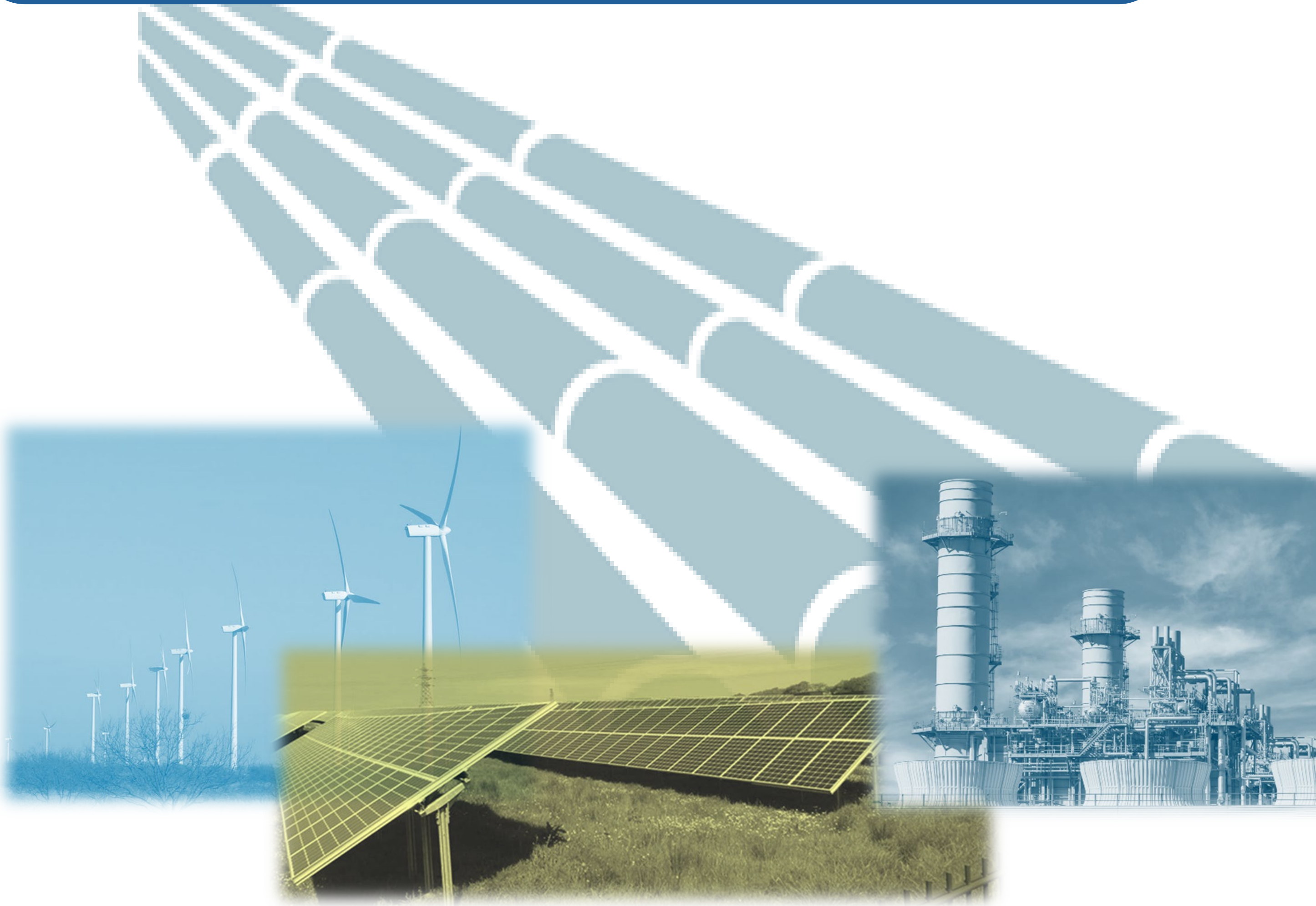
A Win-Win Solution to Finally Achieve Electric & Gas Market Synchronization



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Abstract

This paper provides the background regarding the electric and gas market synchronization issues and provides proposed solutions that, if implemented, would solve those issues. Our market focus in this paper is on the operational and price formation interactions between the wholesale electric markets and the wholesale natural gas market.

This solution discusses hourly pricing of existing pipeline capacity and related services utilized to provide hourly non-ratable service[1] to electric generators whose locations lack firm, primary[2] contracts from supply location(s) to consumption location.

Additionally, this paper will discuss a rate design and rate structure for incremental pipeline expansion projects targeting the ever more variable electric generation loads expected from increasing electric demand coupled with increasing reliance on renewable generation sources.

Finally, the paper outlines the impact on both gas and electric market participants, as well as suggested next steps.

The authors welcome feedback on our proposed solutions. We also are open to meeting and discussing this with various stakeholders to hopefully see these solutions implemented.

We apologize in advance for the length of this paper, it is not a simple issue and the solutions and impacts require a robust explanation.

The information, solutions and data contained herein are provided solely for the purpose of presenting the authors' views, opinions, and ideas.

Skipping Stone makes no warranties, either expressed or implied, concerning the accuracy, completeness, reliability, or suitability of the content of this paper.

[1] Hourly non-ratable service is a load-following service that matches supply to varying hourly demand throughout a day and differs from uniform (ratable) hourly service throughout a day.

[2] Primary firm contracts are those bilateral agreements between a pipeline and a shipper; which agreements have firm receipt point, delivery point and path quantities for a specified term. Such primary contracts would not include "lateral-only" facilities contracts which contracts cover pipeline cost recovery for laterals to bring gas from a pipeline's mainline to the generator.

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Solution Criteria

Criteria 1. Pipelines Need to be Compensated for Providing Non-Ratable Hourly (load-following) Service to Generators.

Natural gas pipelines provide a service critical to the electric grid, i.e., hourly load-following delivery service to gas-fired generators. This service is essential to electric grid stability and resilience, especially during the transition to a predominantly renewable generation future, yet this load-following service is unpriced and essentially free. Continuation of the status quo is not a workable situation and isn't fair to either the pipelines or those shippers who pay fixed charges for existing pipeline capacity services. In this White Paper, the authors propose that pipelines charge for their provision of load-following non-uniform hourly (non-ratable) delivery services to gas-fired electric generators.

Criteria 2. Coordination and a New Non-Ratable Service Model Needs to be Hourly, not Daily.

In our previous White Paper on the topic of gas-electric harmonization, we argued that the two industries would be better able to coordinate if their North American economic "days" were the same. In that paper, we observed that the natural gas industry's single economic day (i.e., 9:00 AM central clock time of one calendar day through 8:59:59 AM central clock time of the next calendar day) did not mesh well with the electric industry's four economic days (i.e., the midnight-to-midnight calendar day for each time zone).

Because the two industries coordinate their current operations at the hourly level very well during more than 95% of the hours in a year, in this paper we propose that the "hour" and not the "day" be the jumping-off point for market structures that will lead to 100% mutual operational coordination in the near, medium, and long-term.

This model of mutual operational coordination driving economic coordination is, in the authors' view, essential to a successful energy transition with increased, but intermittent, sustainable energy backstopped by gas generation making the overall energy supply completely reliable, resilient, and stable.

Criteria 3. Pipeline Expansions to Serve Electric Grid Needs Should Apply Load Factor Based Rate Design to Recover Costs.

Inside, the authors present a volumetric, load-factor-based rate design to recover costs associated with pipeline expansions to meet increasingly volatile and growing gas demand arising from gas-fired electric generation.

Criteria 4. A Solution Should Benefit All Stakeholders.

Any solution should be based on extending what *works operationally* between the gas delivery and electric generation sectors today and should add to that operational coordination a pricing and cost recovery mechanism workable for both pipelines and gas-fired electric generators.

With respect to gas-fired electric generators, the solution must fit within cost recovery and price formation processes in the ISO markets so generators can imbed it into their business processes.

For the pipelines, the approach should build from and advance the longstanding gas transportation market design.

Such a solution should not only address the current non-ratable services provided to locations lacking primary firm delivery service but should also provide a path to compensating pipelines for expansions needed to serve new electric generation, as well as current and future peak hour loads.

Finally, the solution should not negatively impact the current pipeline-shipper operations or economic model, nor penalize shippers who have committed to long-term pipeline capacity contracts. For non-ratable services performed by pipelines with existing capacity, such new revenues are proposed to be shared with existing firm shippers paying straight fixed variable rates for the existing capacity.

Solution Background

Before we dive into how this proposed solution and rate structure works, one should first understand how the two markets' economic models were historically, and are currently, organized.

Electric Transmission and Distribution Cost Recovery vs. Gas Pipeline Cost Recovery

At present, nearly without exception, cost recovery of *existing* electric distribution, transmission capacity, and transmission and distribution capacity *expansions* throughout the North American electric grid are socialized, that is, paid for by all the users in the pertinent region.

This is not the case in the interstate gas pipeline market. A brief overview of the history of the natural gas pipeline market (see Appendix A) is helpful to lay the foundation for both the challenge and solutions.

See Appendix B for an explanation of how gas-fired generators' "heat rate" connects the economics of the gas industry's delivered cost of fuel to the electric markets' hourly price formation and hourly generation dispatch.

Pipeline Transmission Costs are Paid for Through Bilateral Contracts for Specific Paths

As part of the restructuring of legacy pipeline sales services to pipeline transportation-only services, FERC[3], adopted a no financial subsidy policy[4], requiring that new capacity being built for "new" shippers had to be paid for entirely by those new shippers. With this policy, the new shippers had to pay their own way without subsidies from existing customers.

This policy is now known as "incremental pricing." Under incremental pricing, no capacity is built unless the pipeline can show that the rates and revenues for the new capacity cover at least the costs of the new capacity and will not require subsidy from existing shippers. Here, an "existing shipper" is a shipper with a capacity contract on the system that was in effect prior to the contract(s) for the "new" capacity. The historic practice of relying on rates for daily capacity was continued under incremental pricing.

At present, unless the pipeline can find a shipper or shippers willing to sign 20-year capacity contracts to bear the costs of the new capacity, that new capacity is not built.

[3] FERC is the Federal Energy Regulatory Commission which has jurisdiction over the interstate natural gas and electric wholesale markets.
[4] This new policy was met with the concurrence of the legacy pipeline sales customers – predominantly local distribution companies (LDCs).

At present, unless the pipeline can find a shipper or shippers willing to sign 20-year capacity contracts to bear the costs of the new capacity, that new capacity is not built.

Under this incremental pricing scheme, if the new shipper is not using their new capacity contract, that new capacity must be made available to any shipper on a secondary firm basis as well as to shipper(s) on an interruptible basis. The rates for secondary use or interruptible use of the new capacity are unrelated to the incremental rates, instead, they are based on then-current system rates for service along similar path(s)[5].

Occasionally a new project's costs (or its purportedly allocated costs) would result in a rate lower than the applicable system maximum rate. In such a case, the system maximum is the applied rate.

These last two points will figure prominently later in this paper when we discuss the needed updates[6] to current gas pipeline market structures needed to accommodate electric generators dependent on load-following and surge-capacity services of pipelines due to both a) the increased use of variable-output renewable generation sources such as wind and solar and b) increased electric demand from data centers, EVs, and electrification of thermal loads.

[5] Firm capacity under existing system rate contracts or incrementally priced contracts can also be sold (released) to willing buyers for short- or long-term periods at prices set by negotiation or auction in accordance with pipeline administered capacity release processes.
[6] These updates build from and off the existing market design to address evolving market conditions.

Fundamentally Incompatible Business Models

Pipelines & Generation are Codependent

At their respective cores, the pipeline business depends on the electric industry and the wholesale electric business depends on the pipeline industry.[7]

Gas-fired generators supply electricity to the grid – baseload, intermediate, peaking, and renewable generation back-up – and, with coal and nuclear generation retirements, those gas-fired generators depend on pipelines providing just-in-time fuel to maintain grid reliability and stability.

Pipelines and producers need electricity to run ever more compressors and all wellhead and pipeline controls, as well as the operations of gas processing plants that prepare raw gas from wells for delivery as pipeline-quality gas suitable to enter the interstate system.

If gas-fired generators don't get gas, they don't generate electricity (absent dual fuel capability). If gas pipelines, producers, and/or gas processors don't get electricity they can't provide the gas needed by gas-fired generators to generate.

In particular, if a pipeline doesn't have the capacity to transport and deliver gas to the generator needing it under the most severe operating conditions, the electricity needed from that generator will not be available… and the power it would otherwise generate may not be available to natural gas facilities needing electricity to operate.

The interdependence of these two industries is not only at the wholesale level, but also at the retail level where residential and commercial furnaces require both electricity and fuel to operate.

As is clear from periodic and repeated episodes, the time of year that this is most likely to occur is the deep winter. Deep winter is when the pipelines provide gas under firm contracts to LDCs who in turn provide that gas to homes and businesses to generate heat. Once all firm capacity on a pipeline is scheduled, there is no additional capacity to meet additional real or potential demands. Notably, the vast majority of interstate pipelines are fully contracted with firm contracted capacity equaling peak period operational capacity.

The interdependence of these two industries is not only at the wholesale level but also at the retail level where residential and commercial furnaces require both electricity and fuel to operate.

[7] The present-day interdependency between the gas and electric industries is only a relatively recent development. At the time the current natural gas wholesale market was adopted (around 1986 - 1993), natural gas-fired generation was seen as a minor gas consumer, whose service needs were seen as being met by interruptible tariffs and hourly service was hardly a consideration.

In short, where and to the extent that the incompatible business models result in a lack of pipeline capacity to serve gas-fired generators during periods of extreme cold weather, this is a problem that needs an economic solution.

Daily Gas Delivery vs Hourly Electricity Requirements

Routinely, pipelines and electricity grid operators communicate throughout their respective economic days both in advance of the gas day (before 9:00 AM Central) and throughout the gas day, sharing information as to generators' scheduled gas[8] versus expected gas burns and the pipelines' current and expected flow capabilities.

In this way, to the extent of available capacity, compression, and line-pack, pipelines move gas purchased by generators to their plants and up-ramp and down-ramp gas deliveries to provide load-following, non-ratable[9] hourly delivery service.

Most pipeline tariffs give the pipeline the power to limit flows (both firm contract and interruptible contract flows) to uniform hourly flow rates. This is known as a ratable flow service, under which the pipeline divides the daily scheduled quantity by the 24 hours in the day and can limit hourly deliveries (and receipts) to 1/24th or 4.166% of the daily quantity per hour.

This said, most if not all pipelines will provide hourly varying deliveries to the extent of operational capacity to all its firm customers, as well as to its interruptible shippers, as long as non-ratable flows do not interfere with the pipelines' firm shippers' service(s) (i.e., the pipelines' contractual obligations).

For instance, LDCs' customers' behavior causes LDCs to routinely experience between 5% and 8% flow hours[10] in the early morning (6:00 AM to 9:00 AM local time) as homes and businesses "wake-up" and use gas to heat water and air, and to cook. This means that between 5% and 8% of all the gas the LDC will receive in a day is received in each of these morning hours.

Then, from mid-morning through late afternoon, the LDC takes less than 4.166% in the average hour. The evening use of hot water, hot air, and cooking leads to a small bump up to or slightly above 4.166% in each hour, and then it levels out in the nighttime and overnight hours. Pipelines have served this largely predictable domestic gas load reliably since inception.

For the most part, this non-ratable load-following service is provided by the pipelines as a convenience to the pipelines' LDC customers. If able, the pipelines provide this service to all their firm customers (and others) to maintain happy customers – especially those legacy LDCs providing the pipelines often as much as 90+% of their annual revenue under long-term contracts.

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[8] Gas on pipelines is scheduled on a 24-hour flow basis. Gas to generators is delivered on an hourly basis as coordinated between the pipelines and the electric grid operators. At present there is no requirement that generators schedule gas on an hourly basis; but they are encouraged by pipelines to communicate anticipated hourly burns,

[9] Non-Ratable is non-uniform hourly flow. Ratable is uniform flow with hourly flow commonly 1/24th of daily flow.

[10] A non-uniform hourly flow amounting to 5% to 8% of daily flow versus a uniform hourly 4.166% of daily flow.

The most important economic feature of this non-ratable service is that it is unpriced, meaning that those customers under the same service schedule that take gas out of the pipeline at uniform hourly rates and others that rely on taking gas out of the pipeline at variable hourly rates pay the same price. In other words, the very valuable load-following delivery service is largely "free."

As expressed in economic theory and as most market participants in any market know, the demand for a valuable service that is free is almost *infinite*; even if the capability to provide this valuable service is definitely *finite*.

As most market participants in any market know, the demand for a valuable service that is free is almost infinite; even if the capability to provide this valuable service is definitely finite.

Depending on the pipeline and its history of service delivery pre-restructuring, this service (of matching supply with varying hourly delivery), is provided under "no-notice service," explicit "hourly service" tariff provisions, or contracts with explicit provisions providing for consecutive maximum 6% hours followed by explicit less than 4% hours. This hourly variation occurs throughout the year to greater or lesser extents.

During peak winter demand periods when all or nearly all of a pipeline's LDCs in geographic locales having the same weather can be simultaneously requiring full contractual amounts, the system can become stressed and hourly flow variation reduced and restricted to tariff limits (i.e., ratable unless the contracted service is explicitly permissive of firm, hourly variation).

Given the increase in gas-fired generation and reduction in coal-fired generation over the past 10 or more years, gas demand for electric generation increases at the same times of the day as it does for LDC demand (morning/early evening).

As a result, to the extent gas-fired generators lack contracts for firm service, the gas pipeline system during extremely cold dark winter mornings faces the greatest stress and may not have the hourly capacity to simultaneously meet all demands. On these days, the service of non-ratable delivery by pipelines is least available (i.e., constrained) and, in some cases, even ratable delivery to non-firm customers may not be available.

Such unavailability of capacity to serve gas-fired electric generators is a contemporaneous condition in many regions. Moreover, such unavailability is projected to increase during the transition to more renewable generation. In addition to the increased demand for pipeline capacity (especially hourly) to backstop the intermittency[11] of renewable generation, there will be increased electric demand from data centers, recharging of electric vehicles (EVs), and electrification of thermal demand currently met by fossil fuels.

[11] Here intermittency refers to renewable generation that is inconsistent in its output. For instance, solar power does not generate when the sun doesn't shine, and its output varies based on cloud cover. Likewise, wind power does not generate when the wind does not blow and varies with wind speed.

Pipeline Expansion to Meet Gas-Fired Generation Needs

The electric market generally allocates the cost for resolving capacity constraints under a guiding principle referred to as "beneficiary pays" which broadly allocates the cost of new transmission capacity across retail electric ratepayers in the region(s) that *benefit* from an expansion.

Conversely, in the pipeline market, only the new user pays for all costs of facilities that relieve a constraint or otherwise create a benefit, which means that absent a private party willing to sign-up for 20 years, no new gas system facilities are built, even if there were a potential public benefit associated with building the new facilities.

Thus, to the extent that a gas-fired electric generator would benefit from added pipeline capacity to serve them, you would think that the generator would enter into the necessary 20-year contract to get the gas capacity needed to feed their gas-fired facility.

In some monopolistic, vertically integrated electric markets, you might be right as the utility can recover the long-term costs from their customers in the rate-based and fuel cost pass-through tariffs model.

In organized wholesale electric markets, referred to as Regional Transmission Operators (RTOs) or Independent System Operators (ISOs), for the most part, not only is electric generator ownership separated from wholesale electric transmission and distribution wires ownership, but control/ dispatch of generation units is centrally determined by the market operator as opposed to each utility in vertically integrated markets. Likewise, the market operator controls the use of the high-voltage transmission assets.

In wholesale competitive electric markets, generators have no rate base and must recover costs primarily in either the energy or capacity markets.[12] In energy markets where generators bid in the day-ahead market and/or the real-time market, and assuming their bid is accepted, the generators are paid the clearing price, which must cover costs and hopefully a profit. In the capacity market, also a bid model, annual payments to generators are based on annual auctions governing an annual payment to be made for the one year that is three years in the future, in most organized markets.

Given the shorter-term nature of organized wholesale electric markets and no rate base for generator cost recovery, it has proven very unlikely for a gas generator to be willing to sign a 20-year pipeline capacity contract.

Given the shorter-term nature of organized wholesale electric markets and no rate base for generator cost recovery, it has proven very unlikely for a gas generator to be willing to sign a 20-year pipeline capacity contract. The primary reason the term of the pipeline contract is considered too risky is that the electric market cost recovery model doesn't enable recovery over that many years.

[12] ERCOT which operates solely in Texas, does not have a capacity market. It is an energy market-only ISO.

Contrary Conditions Likely to *Increase* Demand for Pipeline Capacity in a World of *Decreasing* Aggregate Annual Gas Demand

An increased demand for peak period hourly capacity is likely to occur even while annual demand for gas is quite likely to decrease.

LDCs in many states are facing requirements to reduce gas demand associated with their current and/or potential customers. Whether it involves bans on new load, energy efficiency increases, appliance electrification, replacement of gas distribution by means of electrification, geothermal sourced heat, or more than one of the above, the projected result is that the trendlines(s) for annual LDC load are flat to declining. Further, some of that decline will also be a flattening to slight decline in design day demand.

While this may appear to be advantageous for gas-fired generation, it's actually the opposite.

Inverse Factors

Renewable generation from solar is largely unavailable before 8:00 AM during winter hours; meanwhile from, at latest, 6:00 AM to 8:00 AM, heating[13] and domestic electrical demand must be met. Plus, electric load is growing and is predicted to increase in rate of growth as transportation and building electrification demands are realized.

Thus, even if peak hour gas-fired generation is not required during daylight hours (i.e., after 8:00 AM on sunny winter days) resulting in less aggregate consumption, *peak consumption* hours (6:00-8:00 am) and attendant capacity demand is *unlikely to decrease*. In fact, the more electrification supported by renewable capacity expands, the more peak hourly gas demand to meet electric reliability needs will grow. Some form of reliable, dispatchable peak hour generation and/or discharge from batteries, demand response or, most likely, gas-fired generation will be needed to power homes and businesses as the day begins.

In fact, the more electrification supported by renewable capacity expands, the more peak hourly gas demand to meet electric reliability needs will grow.

Whether and to what extent batteries, demand response, or pipeline capacity is the source of such peak-hour electric supply is and will be a matter of competition and availability. The outcome of that competition will not only be determined by price but will also be a function of timing and scale of deployment as well as fitness for long-duration applications. More pointedly, this peaking and balancing service is critically necessary and valuable, yet the pricing structures to call it forth from the market are largely lacking.

[13] Here heating demand, exists and will continue to prevail, whether met directly from natural gas consumption or electrified heating.

Operational Aspects

The good news is that some 95+% of the time, even though they have incompatible business models, the two industries cooperate and coordinate to make things work, keeping the lights on and the gas flowing.

So, the question is…how can we use the situation where they work more than 95% of the time to enlighten and guide us to a market structure solution? One that can be the means of making their cooperation and coordination work to ensure resilient, interdependent, and stable operations 100% of the time.

So, the question is… how can we use the situation where they work 95% of the time to enlighten and guide us to a market structure solution?

As the authors see the current and future conundrum, new pipeline capacity will apparently be needed to support peak hour electric generation while the traditional pipeline capacity subscribers (LDCs) are faced with flat to declining annual demand[14], the solution needs an innovative pricing and service approach not present in today's market.

In addition, any solution should be based on extending what *works operationally* between the gas delivery and electric generation sectors and adding to that "operational coordination" a pricing and cost recovery mechanism workable for pipelines. Additionally, it must be one that fits within cost recovery and price formation processes in the organized wholesale electric markets so that it fits generator operating and business needs.

Such a solution, discussed in detail below, should not only address currently provided non-ratable services provided to locations lacking primary firm delivery service, but also should provide a path to compensating pipelines for expansions needed to serve new electric generation loads as well as current and future peak hour loads. By so doing, the market could provide an investment price signal and impetus that it currently lacks.

A Visual Representation of Non-Ratable Service Provided to Electric Generators

Below is an indicative graphic representation of a pipeline system's hourly load-following service to gas-fired electric generators.[15] The red line represents, in aggregate, the hourly burn shape of gas-fired electric generators on its system. The blue line represents what a uniform hourly demand for the daily quantity would look like (i.e., 1/24th flow each hour of the daily burn by gas-fired electric generators).

[14] Peak day/peak hour LDC demand may also flatten or decline slightly; however, electrification of that demand largely shifts the LDC demand to gas-fired electric generation demand.

[15] This graphic is derived from Enbridge's Algonquin Gas Transmission system's proposed Project Maple as contained in its open season brochure. See https://infopost.enbridge.com/GotoLINK/GetLINKdocument.asp?Pipe=10076&Environment=Production&DocumentType=Notice&FileName=Maple+Open+Season+Final.pdf&DocumentId=8aa164b28a8404b0018a848cd1230040

The dashed line is the daily equivalent pipeline capacity required to serve the peak hour of the aggregate hourly gas-fired electric generator demand (load).

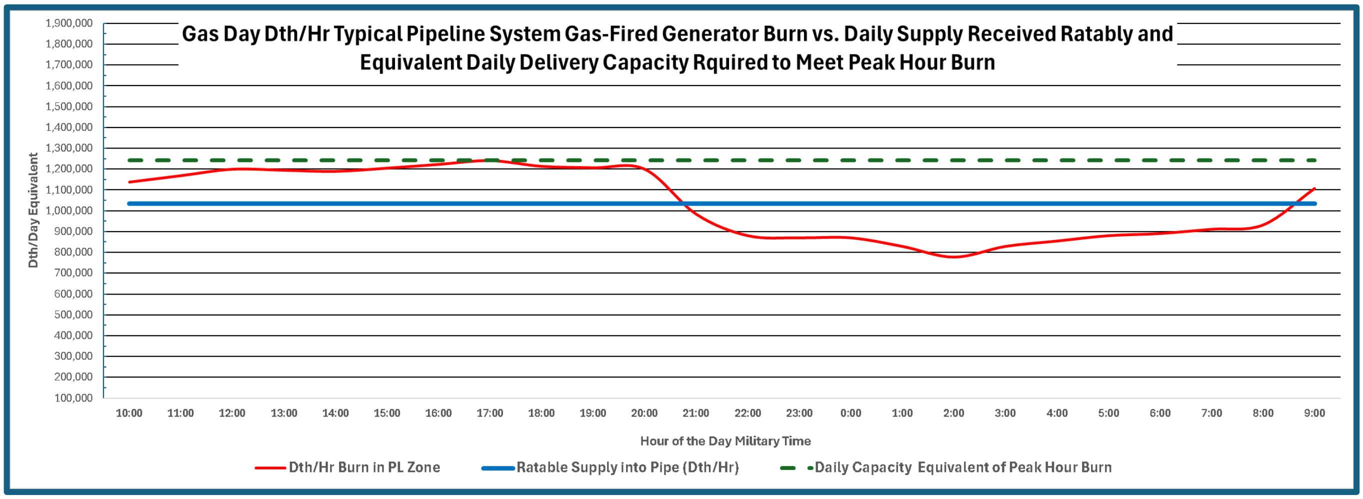

Figure 1.

The Operational Aspects of Non-Ratable Service Provision and Related Pricing

The provision of non-ratable service by pipelines to electric generators involves resolving both the capacity problem (to provide such non-ratable service), and the operational problem (varying supply to match demand) that together apply to the "gas inside the capacity."

The Operational Issue of Varying Supply to Follow Demand

The gas inside the capacity problem means dealing with the operational issues of where is the gas *coming from* when needed for generation and where is the gas *going to* when not used for generation.

The problem is one of simple physics. When flow into a pipeline is at a constant hourly rate, but flow out of the pipeline is not, other pipeline or gas system assets[16] must absorb the excess in-flow and provide the excess out-flow.

Alternatively, where the in-flow (supply) from one or more locations can operationally match variable out-flow (demand), such other pipeline or gas system assets may not be required to provide variable, load-following *supply*.

Looking deeper at this operational gas issue associated with non-ratable service, we know that pipelines are not elastic and line pack, especially during peak periods, is a limited resource. As a result, such service will need to lean on either a) existing pipeline owned/operated storage assets, b) high deliverability/high injection storage assets of third-parties within operationally compatible distances from the generators' locations, c) injection of LNG/CNG supplies within operationally compatible distances from the generators' locations, or d) diversion back to the wholesale gas market

[16] Such assets, depending on hourly quantity, would be storage assets, whether they be horizontal (line pack) or vertical (storage field(s)' storage wells) assets operated by the pipeline or third parties.

of a portion of gas destined for large industrial plants[17] to provide supply when takes exceed minimum, ratable, hourly take conditions.

A Visual Representation of Cumulative Storage Withdrawal and Injection Quantities to Provide Aggregate Non-Ratable Service to Electric Generators

The following graphic is a representation of a) the cumulative buildup of gas withdrawn from storage when gas-fired generator burn exceeds uniform hourly flow, as well as b) cumulative injection into storage when uniform hourly flow exceeds hourly aggregate burn by gas-fired electric generators.

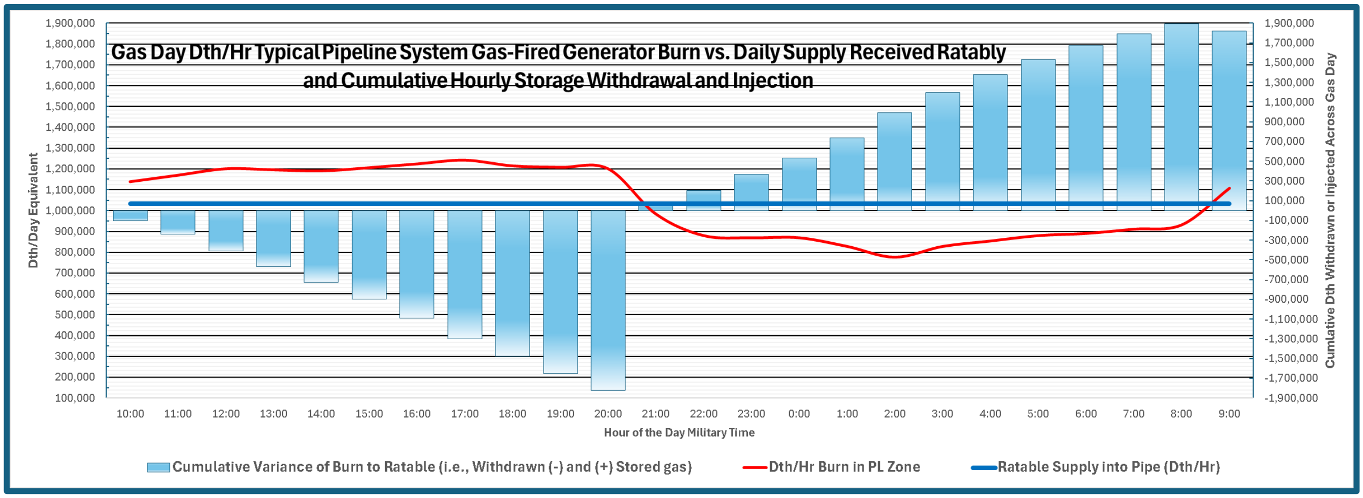

Figure 2.

[17] Here diversion of a portion of large industrial demand would be where the large industrial consumer sells to the generators directly, or to marketers serving electric generators, a portion of their daily supplies by "turning down" production because it is more profitable to sell that gas than to produce the products made with/from such gas.

The Solution

The solution to this indeterminate quagmire involves addressing both the 'capacity' and 'gas within the capacity' elements of non-ratable consumption. Several approaches to addressing these elements are described in the following sections, beginning with the price of gas within the capacity.

A. Pricing the Pipeline-Provided Varying Supply to Match Demand Service

In the case of the use of existing pipeline-owned/operated storage assets, the "price" for this service could be based upon rates up to applicable maximum rates (discussed further below) for **(New) Hourly Park and Loan (PAL) Services.** In short, appropriately pricing hourly PAL can address the "gas inside the capacity" issue when the pipeline is the one dealing with the gas component of non-ratable gas delivery service.

...appropriately pricing hourly PAL can address the "gas inside the capacity" issue...

Unlike currently offered daily PAL services, which are priced at daily volumetric rates based on the pipelines' 100% load factor equivalent of firm daily transportation rates, an *hourly* PAL service rate should incorporate per Dth[18] rates derivative of the pipelines' storage injection and storage withdrawal rates, as well as per Dth rates for transportation capacity (discussed below. [19])

Figure 2 above indicates the by-hour quantities for the "loan" portion of the pipeline-provided hourly PAL service, followed by the hourly quantities for the "park" portion of the hourly PAL service.

B. Pricing the Third-Party Provided Varying Supply Using Storage to Match Demand Service

In the case of third-party storage, the price for the gas can be competitively determined by negotiations between the party with contractual control of the third-party or parties' assets[20] providing the supply-demand matching service and the generator using the supply matching service.

Figure 2 also indicates the by-hour quantities of the third-party provided matching service when the total daily supply scheduled to the generator location equals the generator's daily burn. In that instance, the third-party hourly usage of storage withdrawal and injection capability is (and has to be) the same as that of the pipeline when providing hourly PAL service.

The following graphic is a representation of another means of matching hourly supply to hourly burn. Here, gas to the generator is made up of uniform hourly supply scheduled to equal the daily equivalent

[18] A Dth or "Dekatherm" is 1 million British Thermal Units (Btu). A Btu is the amount of energy required to raise the temperature of a pint of water 1 degree F.

[19] Where a pipeline already has firm hourly service rates, a volumetric derivative of such rates could form the basis of hourly PAL service rates.

[20] Here, third-party(ies) means one or more party(ies) operating storage facilities under contract with the generator to provide hourly match of flow to hourly burn.

of minimum hour burn. Hourly burns above such minimum quantity are supplied wholly from third-party withdrawal from storage.

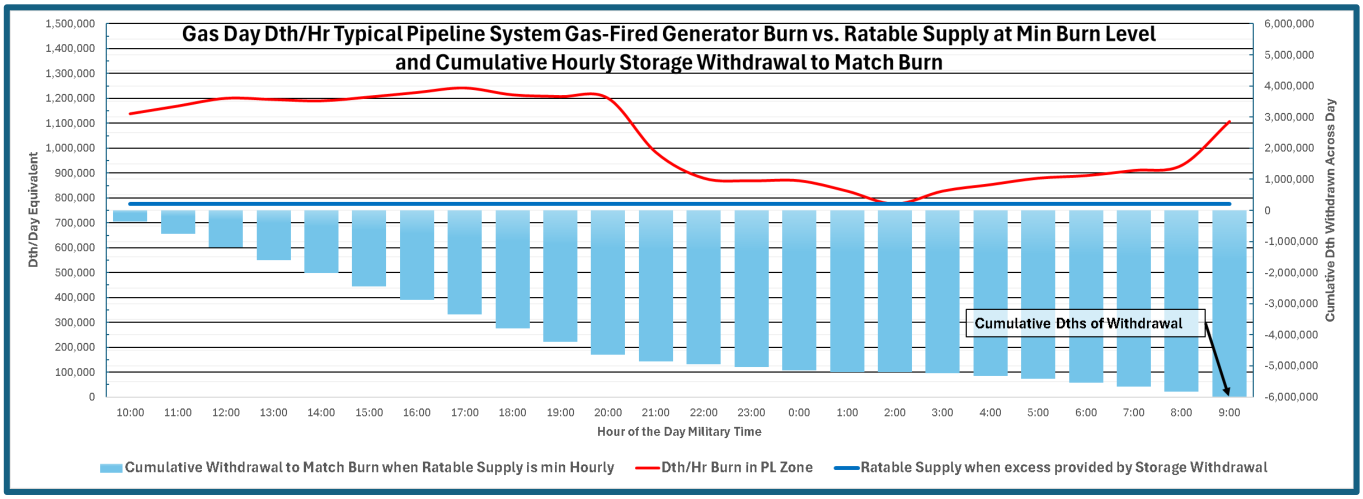

Figure 3

C. Pricing the LNG/CNG Injection Service of Matching Supply to Demand in Excess of Ratable/Uniform Takes

In the LNG/CNG injection case, the price for the gas, like that in the third-party storage cases can be determined between, on the one hand, the party with ownership of the LNG/CNG and contractual control of the LNG/CNG injection service, and on the other hand, the generator using the injected gas.

D. Identifying the Capacity to Provide Non-Ratable Service Problem

Separate from the "matching gas supply to variable demand issue" and its distinct pricing solutions is the pricing problem associated with the provision of the pipeline capacity to effectuate hourly variable deliveries.

E. Focusing on the Infinite Demand for a Valuable yet Unpriced Service and the Lack of Actionable Price Signals

As discussed above, the provision of non-ratable service by pipelines to electric generators involves identifying and resolving the unpriced service aspect of the "capacity to provide such service" problem. A service that is valuable yet unpriced will experience infinite demand. In addition, an unpriced service does not send price signals in response to which market participants can make investment and substitution choices. Investment decisions would be those made to provide more of a valuable service. Substitution decisions would be those made to avoid paying for higher-priced services and instead pursue substitutions (e.g., battery storage) that address the electricity need at a lower price.

> ***A service that is unpriced will experience infinite demand.***

The Two Pricing Aspects Related to the "Capacity to Provide Non-Ratable Service" – Straight-Fixed-Variable Rate Design Versus Volumetric, Load-Factor Based Rate Design

In today's wholesale gas markets, pipelines have volumetric rate designs for firm service to a particular set of customers. That particular set consists of small, generally municipal, LDCs.[21] This volumetric firm service is a vestige of the original rate design used for pipelines when they first began service as merchants. The name used for that initial rate design was the "United" Rate Design. The volumetric (no fixed reservation charge) rate for these small customers is a load-factor-based rate.

What are "Load-Factor" Based Rates?

A load-factor-based rate is a regulatorily established way to collect a pipeline's annual costs for providing service over an assumed annual use of that service. For "small customer" volumetric firm service rates, they are most often set at a 60% load factor. In the case of volumetric non-firm services (i.e., interruptible transport or IT service), they are set at 100% load factor.

A 100% load factor rate is derived by multiplying the monthly reservation rate for a path service times the number of months in a year and dividing that number by the number of days in a year which yields a rate that would collect the annual cost of that service if used and paid for every day of the year. (monthly reservation rate x12/365)

A 60% load factor rate is derived by multiplying the monthly reservation rate for a path service times 12 and dividing that number by 219 (60% of the number of days in a year) which yields a rate that would collect the annual cost of that service were it used and paid for over the year at a 60% load factor. Assuming the daily contract quantity was 1,000 Dth, the annual quantity in this example would be 365,000 Dth. The 60% load factor rate assumes the pipeline will recover its costs when the small customer uses 219,000 Dth in the year.

Notably many small customers are municipal gas systems that, on an annual basis, operate at 30-40% or less load factors. While the 60% load factor rate may under-compensate pipelines for this service, most pipelines have many small customers and over the years, it has made practical sense for the pipelines to not disturb this vestigial rate design. Generally, this is also because the maximum daily quantity for any such customer is limited and there are few, if any, new towns (municipalities) being created along pipeline routes, so the negative economic impact on the pipelines is unlikely to increase.

[21] Municipal LDCs are "small" both in terms of peak day and annual demand and are typically very low load factor – often less than 30%.

F. Charging a Default Volumetric Rate to Generators for Their Hourly Takes in Excess of Ratable Hourly

Above, the methods of pricing for the "gas inside the capacity" were addressed. Here we address the pricing for the use of capacity to provide non-ratable delivery service.

When a pipeline is using existing capacity to serve hourly generator load above uniform (ratable) hourly equivalent of daily quantity, the pipeline should be permitted to charge the equivalent of its then effective volumetric firm rate (discussed below) for the 95% of cases that are presently addressed by unpriced operational coordination. In addition, we discuss below the maximum volumetric rate applicable to new capacity built by the pipeline to serve generator load for the 5% where operational coordination is lacking due to insufficient capacity.

When a pipeline is using existing capacity to serve hourly generator load in excess of uniform hourly equivalent of daily quantity, the pipeline should be permitted to charge the equivalent of its then effective volumetric firm rate.

In short, current non-ratable use of existing capacity above ratable hourly capacity should be volumetrically priced hourly. Of course, pipelines could file with the FERC to charge a different volumetric rate for use of capacity in excess of ratable, but absent such filing and FERC approval, a default rate based upon a 60% load factor of the applicable firm transportation rate can begin to solve the unpriced service problem.

As previously shown in Figure 2 (page 13), a pipeline's system-wide deliveries to generators exceeding ratable hourly occurred in 12 of 24 hours. This 12 of 24 would indicate that a 50% load factor rate would also be appropriate.

G. Adding Capacity to Serve Generators Unwilling/Unable Economically to Commit to Long-Term Fixed-Variable Rate Contracts

Even though electric generation is a market that is somewhat averse[22] to long-term pipeline capacity contracts, with the right rate structure, it can be possible to build needed pipeline expansion to serve said electric generation, while benefitting the gas grid, the electric grid, gas-fired generators, gas consumers, LNG suppliers, renewables development, and the environment.

Under the proposed structure, a pipeline expansion can be built without reliance on long-term contracts.

Under the proposed rate structure, a pipeline expansion can be built without reliance on long-term contracts. This can be done with tariffs providing volumetric rates based upon projected load factor utilization of the expansion capacity

[22] Taken as a whole, electric generators are "somewhat" averse because electric generators in vertically integrated electric markets are less averse, while electric generators in competitive electric markets are very averse to long-term pipeline capacity contracts.

and charged to generation locations when the pipeline uses that capacity to provide service. This will be discussed in further detail later.

At a time when annual gas use is projected to decline, but reliance on gas for the combination of peak day generation[23] and remaining heating load persists (and in the near term may increase), the proposed volumetric rate structure shields existing LDCs and their existing residential and commercial gas consumers from the burden of long-term fixed costs, while at the same time placing cost recovery for the pipeline on electric generators also able to recover their costs through the wholesale electric market.

H. Economic Coordination with Appropriate Service Pricing Coupled with Operational Coordination

This latter point, that a volumetric rate for service applicable to electric generators, and charged when they use it, is consistent with wholesale ISO markets' price formation and cost recovery models and is also fundamental to fostering long-term gas-electric industries' mutual success, resiliency, and stability.

Because variable costs can be bid into ISOs' Energy Markets, and both the gas price and the transportation capacity prices as-charged are variable,[24] the gas and electric markets can economically coordinate their pricing and cost recovery in the hourly markets[25] – just as they operationally coordinate over 95% of the time today – leading to their long-term 100% coordination as to both investments and substitution choices.

I. Applying Load Factor-Based Rate Design to Recover Costs from Needed Expansions to Serve New Electric Generation Demand

It should be acknowledged here that the volumetric nature of the rates, especially for service provided by new capacity, puts the pipelines at-risk for cost recovery. Much like the pipelines' initial role as merchants, this proposed rate design is consistent with the pipelines operating, with respect to this service, as Capacity Merchants.

… this proposed rate design is consistent with the pipelines operating…as Capacity Merchants.

Example of Load-Factor-Based Maximum Rate

For the purpose of presenting a rate design applicable to providing additional load-following service to electric generators, consider the following example.

Assuming that for 95% of the hours in a year gas-fired electric demand is met and an expansion of some amount would enable 100% of the hours of gas-fired electric generation demand to be

[23] Including peak day/peak hour capacity backstopping intermittent renewable generation.
[24] Variable equals volumetric costs to generate electricity.
[25] Here the hourly markets refer to both day-ahead and real-time for each of the electric and gas markets.

met, the new capacity would have a 5% utilization. This means the load factor utilization would be 5% of the hours in a year (438 hours – or 8,760 times 5%). Assume also that the unmet hourly demand during this 5% of hours was 15,000 Dth/Hr (360,000 Dth/d).

Finally, assume the *economic life* of the assets needed to provide the additional hourly service was 10 years (i.e., competitive substitutes, declining peak heating demand discussed above may make the new capacity unused ten years after installation) and thus the depreciation rate (i.e., the return of capital) should be 10% annually instead of the typical 2% +/- seen in rates currently[26] due to the assumed 10 economic year life of the expansion.

A thumbnail annual cost recovery for new capacity assuming current economic factors and rate design is around 15-20% of each dollar invested. This new depreciation factor, along with higher return, interest, and amortization rates on shorter-term debt, is estimated to bring annual per-dollar-invested cost recovery and profit, (i.e., cost of service) to around 30% of each dollar invested.

For a modeled 360,000 Dth/d capacity expansion that today has a recourse (filed for maximum rate) of $1.00/Dth per day it would typically have an approximate $660 MM capital cost and an approximate annual cost of service of $132 MM. Changing the thumbnail annual revenue requirement from 20% of capital to 30% of capital raises the annual revenue requirement to approximately $197-$200 MM. Finally factoring in that the 15,000 Dth/H of capacity will be used across 438 hours, the indicative maximum rate[27] for use of this capacity would be $30.00/Dth per hour.

Assuming a peaking, simple cycle, generator's heat rate is 10,000 Btu/kW (10 Dth/MW), the variable pipeline capacity cost component of the generator's bid to the electric grid would be $300/MW; and, assuming $10/Dth gas – the bid to the grid (excluding grid allowed generator add-ons) would be $310/MW for those hours when the new capacity was required based on electric generator demand.

J. When and Where the Volumetric Load-Factor-Based Rate Would and Would Not Apply

There are two important considerations here: a) ***what are the locations*** where this service is provided, and b) ***when is it appropriate*** to charge the volumetric, load-following, load-factor-based rate?

First, as to the where, it is important to determine both where (i.e., to which locations) the service *would be* deemed to have been provided and, equally important, which locations *would not* be subject to this volumetric hourly rate.

[26] Current pipeline system rates have as a component of cost of service a return of invested capital (i.e., depreciation rate) in the 2% +/- range which infers a 50-year economic life for the pipeline systems' assets.
[27] As with all pipelines' maximum rates, pipelines could determine to discount such rates to as low as the minimum variable usage rate; but of course would see possible non-recovery of costs.

Locations covered by firm contracts with path(s) from *primary*, mainline supply receipt points to *primary* delivery points whose capacity (and/or relevant tariff provisions[28]) provides hourly delivery capacity varying from uniform and/or equal to or greater than scheduled and taken deliveries *would not* be subject to the volumetric rate.

Deliveries to/takes at locations enabled by firm contracts but on a secondary basis *would be* eligible for the service and subject to the volumetric rate(s).

K. Setting the Prerequisite Conditions for When this Load-Factor-Based Volumetric Rate for New Pipeline Capacity to Serve Non-Ratable Generation Demand Becomes Appropriate

For the purposes of charging a volumetric load-factor-based rate for the use of ***new*** Merchant Capacity, (aka Volumetric Merchant Capacity or VMC) it is first necessary for all market participants, market monitors, and stakeholders to know the quantity, extent and capability of ***existing*** capacity. So, as an initial matter, existing capacity needs to be identified and delineated on a Dth/hour location by location and segment basis assuming full primary location and path scheduling of existing firm contracts.

Existing capacity needs to be identified and delineated on a Dth/hour location by location and segment basis assuming full primary location and path scheduling of existing firm contracts

The appropriate application of a VMC hourly rate is knowing the capacity of the system to serve loads being met with firm legacy and incremental capacity contracts (i.e., associated with previous expansions) under long-term agreements before the addition of the capacity[29] whose cost recovery is by means of VMC rates.

Every pipeline knows its hourly capacity and throughput capability by compressor station. Pipelines also know hourly receipts and hourly deliveries as well as instantaneous pressure readings at all significant receipt and delivery locations on their systems. Pipelines monitor these figures and readings and employ them when warning of and enforcing flow rules utilizing OFOs (Operational Flow Orders).

Notably, pipelines also forecast near future flows by segment/geographic footprint based on sophisticated weather forecast-to-demand models and in coordination with ISOs/generators overlapping the pipelines' delivery locations.

[28] Here, tariff provisions would include no-notice scheduling provisions, defined and permitted hourly flow rate variations; and/or hourly service contracts.
[29] Capacity added after Merchant Capacity expansions that are covered by long term incrementally priced contract(s) would become existing capacity for the purposes of determining applicability of VMC rates.

Notification of Near Future Applicability of Volumetric Merchant Capacity (VMC) Hourly Rate

In much the same manner and following similar applicable processes (in regulations and tariffs) governing notification of potential OFO conditions and associated penalties, pipelines can notify the public through its System Notices and Critical Notices[30] of the near-future applicability of the VMC rate.

The Geographic Pipeline System Applicability of Notice and Charges

To coordinate pipeline service pricing with the ISOs' Energy Market price formation processes, the geographic extent of pricing should be the greater of the pipeline's rate zone or the ISO's footprint overlapping the pipeline's footprint. This formulation eliminates potential market disruption between the electric and gas markets and also eliminates the benefit market participants may seek via generation-shifting strategies to either avoid the VMC Hourly Rate or have it imposed on others besides the generation-shifting market participant.

Other Current Mechanisms for Determining When VMC Hourly Rates Apply

Given these available processes, notice timing, geographical applicability, and knowable physical facts and associated firm capacity figures coupled with the pipelines' computerized flow models and annual mandatory capacity filings with the FERC[31], it will be possible to ascertain pipeline flow capabilities pre-merchant capacity expansion and what increment(s) of capacity come into existence post- Merchant Capacity Expansion(s). It would be the utilization of those increments of Merchant Capacity that would trigger applicability (as discussed above) of the VMC Hourly Rate[32].

[30] Both Critical Notices and System Notices are required, by FERC regulations, to be posted and in many cases sent directly to affected and potentially affected parties.

[31] Pipelines are required to annually file what is referred to as Form 567 which delineates peak day flow and design factors of compressor horsepower, compressor inlet and outlet pressures, pipeline segment diameter and mileage among other factors.

[32] As opposed to the applicability of the default 60% load factor rate for non-ratable capacity use not requiring use of the Merchant Capacity.

L. Synchronizing Volumetric Charges for Non-Ratable Service Using *Existing* Capacity with Volumetric Charges, Including Non-Ratable Use, of *Merchant Capacity*

Once existing pipeline capacity (i.e., that capacity not considered merchant capacity) has been nominated, provision by the pipeline of service (including non-ratable service) to any and all applicable locations (as discussed above) would be subject to charges up to the maximum VMC rate. The pipeline can choose to discount the maximum VMC rate on a non-discriminatory basis.

A "one price for similar service to similar markets" approach assures that the complications of determining whose load "passed the threshold" would not lead to years of litigation and regulatory wranglings.

A 'one price for similar service to similar markets' approach assures that determining whose load 'passed the threshold' would be avoided.

Thus, rather than focusing on who pays the price, we suggest focusing on who gets the monetary benefit of the increased revenue.

M. Sharing of Revenues from Non-Ratable Use of Existing Capacity

Revenue collected by the pipeline for non-ratable service provided without reliance on the merchant capacity would be subject to revenue sharing between the pipeline and its firm customers paying for capacity within the zone(s) enabling the non-ratable service. An 80/20 customer-to-pipeline split might be a workable starting point for this revenue sharing. To the extent that pipelines currently collect revenues for non-ratable service in the form of penalties, and those penalty revenues are flowed back to firm customers, we suggest that charging for a provided service is preferred over assessing penalties for provided service.

An 80/20 customer to pipeline split might be a workable starting point for revenue sharing.

N. Pipeline Revenue Retention for Use of Merchant Capacity

Revenue collected by the pipeline for all services, ratable and non-ratable, provided in reliance on the merchant capacity would be solely for the account of (i.e., retained by) the pipeline. This revenue (collected through VMC rates) and associated capacity-related costs for the merchant capacity would be separately tracked and excluded from general Section 4 rate cases. Likewise, the capital invested in creating merchant capacity would be excluded from the rate base for system rate case cost allocation and rate design purposes.

… the capital invested in creating merchant capacity would be excluded from rate base for system rate case cost allocation and rate design purposes.

O. What Contractual Mechanism Could be Used to Assess These Volumetric Charges?

At present, FERC regulations require pipelines to enter into Operational Balancing Agreements (OBAs) at all significant receipt and delivery locations with third parties. These OBAs contain various balancing provisions, with most OBAs having varying magnitudes (aggregate quantity) of permitted imbalances and varying time periods over which imbalances must be physically resolved or "cashed-out."[33]

We suggest that pipelines be required to file with FERC the hourly balancing and associated charging language to be used in their OBAs with generators.

We suggest that pipelines be required to file with FERC the hourly balancing and associated charging language to be used in their OBAs with generators.

Volumetric charge collection provisions[34] (both for non-ratable use of existing capacity and use of merchant capacity) should be placed in the OBAs rather than in the transportation agreements because the shippers transporting gas sold to generators often do not control the takes or hourly shape of takes by those generators; thus, having the charges assessed directly on the generators makes for easier cost auditing by the ISOs, should that be necessary or customary.

[33] Cash-out is generally a process where imbalance gas owed ***to*** the pipeline by the interconnecting party or owed ***by*** the pipeline to the interconnecting party is settled in money based on discounts to or premiums on published posted prices applicable to the location of the imbalance.

[34] The volumetric charges would encompass the generator location's use of hourly PAL (where applicable) and hourly capacity use for deliveries in excess of ratable hourly use.

Market Participant and Stakeholder Impact

Following is a discussion of what we believe will be the effects of the proposed introduction of a pipeline-administered pricing mechanism for non-ratable service on the economics, market behavior, and/or business opportunities of the various market participants and stakeholders[35] in the gas and electric industries respectively.

For convenience, we use the market segment identifiers employed by members of the North American Energy Standards Board to self-identify and allocate votes on standards. To pass a standard, NAESB procedures require super-majority support within/across an industry (e.g. gas, electric, and retail[36]) as well as a required level of minority support across each market segment.

Wholesale Gas Industry Market Participants/Stakeholders

Pipelines

Pipelines will administer the measurement and pricing of non-ratable service provided to gas-fired generators. The pipeline *will not charge* for non-ratable service at locations covered by primary delivery capacity designation under firm, primary contracts from supply location(s) to consumption location.

Economic Impacts: The pipelines are *permitted to charge for non-ratable deliveries to locations that lack* primary delivery capacity designation under firm, primary contracts from supply location(s) to consumption locations. That is, locations not covered as primary delivery locations with contractual daily primary firm hourly capacity rights that equal or exceed measured hourly flow.

When pipelines employ existing capacity to provide such non-ratable services, they are permitted to charge for capacity used.

When pipelines employ existing capacity to provide such non-ratable services, they are permitted to volumetrically charge for capacity used. These charges would be for hourly deliveries above ratable, up to maximum rates defaulting to 60% load factor volumetric rates of the applicable zone. When pipelines provide hourly PAL service to provide load-following gas supplies, they are permitted to charge rates incorporating system rates for storage capacity, injection and withdrawal plus the current 100% load factor transportation rate applied to such hourly PAL quantities. The authors suggest that the pipelines be permitted to retain 20% and share with firm customers 80% of such revenues generated from such hourly PAL and non-ratable delivery capacity services. The logic behind revenue

[35] Here, a stakeholder can be seen as one or more entities whose roles are not economically impacted by the proposed new rates for pipeline-provided load-following services.

[36] Respectively, NAESB currently refers to Wholesale gas interests as the Wholesale Gas Quadrant (WGQ); Wholesale Electric Interests as the Wholesale Electric Quadrant (WEQ); and the Retail gas and electric interests as Retail Markets Quadrant (RMQ).

sharing is that the pipeline is using existing capacity paid for by existing customers to generate the new revenue.

When pipelines build new capacity (Merchant Capacity) on an at-risk basis to provide services additional to the level of service available from existing capacity, and that capacity is utilized, they are permitted to charge, on a non-discriminatory, volumetric basis, Volumetric Load-Factor-Based Rates (VMC rates) to all applicable locations once the new capacity becomes needed to effectuate ratable and/or non-ratable services. In these instances, the pipelines are permitted to retain all such VMC revenues.

Market Behavior Impacts: Pipelines are anticipated to measure and further coordinate with ISOs and generators as to projected and real-time hourly flow. OBAs will be the contractual mechanism for collecting such charges. Pipelines will employ Critical Notice procedures to inform market participants and stakeholders of the pendency of VMC Rates.

Business Opportunity Impacts: Given a potentially remunerative revenue stream associated with both pipeline provision of non-ratable service employing existing capacity and provision of services employing Merchant Capacity. This allows pipelines an opportunity to grow revenue in a potentially declining annual throughput environment.

This allows pipelines an opportunity to grow revenue in a potentially declining annual throughput environment.

Gas Producers

Economic Impacts: Producers are likely to be largely unaffected by the proposed rate changes except where 1) they receive revenue sharing amounts based on their firm capacity contracts in zones where non-ratable services provided with existing capacity are generated and 2) they are compensated by providing (selling) load-following supply to generators.

Market Behavior Impacts: Producers are not anticipated to alter their daily or long-term supply responses or capacity contracting based on the introduction of non-ratable service charges by pipelines to generators. Neither are producers likely to alter daily supply sales and related scheduling procedures between them and their pipelines and/or buyers of their supplies.

Business Opportunity Impacts: Other than assessing the benefits/costs of introducing technology, facilities, and willingness to make intra-day flow changes to match non-ratable supply to non-ratable burn, the authors do not envision that producers' business opportunities will be directly impacted.

LDCs

Economic Impacts: Provided their capacity contract(s)/tariffed services have provisions allowing non-ratable takes, LDCs are likely to be largely unaffected by the proposed rate changes except where 1) they receive revenue sharing amounts based upon their firm capacity contracts in zones where non-ratable services provided with existing capacity are generated and 2) they are compensated for providing (selling) load-following supply to generators utilizing the LDCs' storage contracts that permit hourly variation in withdrawal and or injection.

Market Behavior Impacts: LDCs are not anticipated to alter their daily or long-term supply or capacity contracting based upon the introduction of non-ratable service charges by pipelines to generators. Neither are LDCs likely to alter daily supply purchases and related scheduling procedures between them and their pipelines or suppliers.

Business Opportunity Impacts: The authors do not anticipate substantial business opportunity impacts (positive or negative) for LDCs.

End-Users (other than gas-fired electric generators – addressed below)

Economic Impacts: Gas-consuming end-users are likely to be largely unaffected by the proposed rate changes except where 1) they receive revenue-sharing amounts based on their firm capacity contracts in zones where non-ratable services provided with existing capacity are generated, and 2) they are compensated for providing (selling) load-following supply to generators employing diversion of hourly supplies where revenues from diversion exceed the value of products produced from such supplies.

Market Behavior Impacts: End-Users are not anticipated to alter their daily or long-term supply or capacity contracting based upon the introduction of non-ratable service charges by pipelines to generators. Neither are End-Users likely to otherwise alter daily supply purchases and related scheduling procedures between them and their pipelines or suppliers.

Business Opportunity Impacts: The authors do not anticipate substantial business opportunity impacts (positive or negative) for end-users.

Gas Industry Services

Economic Impacts: Gas Industry Services segment members encompass marketers and software and related service vendors. Marketers holding firm capacity contracts are either 1) insulated from charges for provision of non-ratable delivery service provided by pipelines to gas-fired generators because those charges are collected by means of the OBAs and not transportation agreements or 2) potentially able to be compensated for providing hourly load-following withdrawal and injection services utilizing storage facilities either owned by them as storage provider or under contract with the marketer providing the hourly load-following service, or 3) able to be compensated for selling to the generator all hourly supplies in excess of minimum hourly (minimum ratable) quantity. For the software and related service vendors no immediate economic impacts are anticipated.

Market Behavior Impacts: Those Services segment entities not competing with the non-ratable supply function of the pipelines (i.e., hourly PAL), are not anticipated to alter their daily or long-term contracting or scheduling interactions with suppliers, pipelines, or customers. On the other hand, to the extent Services segment entities assemble contracts and/or assets able to provide load-following supply to gas-fired electric generators, their interactions with the pipelines will increase in frequency both as to within-day and day-ahead scheduling. Interactions with gas-fired electric generator customers will similarly increase in frequency.

Business Opportunity Impacts: Numerous and expansive business opportunity benefits and threats are projected for this segment. On the positive side, marketers, storage operators, and software services focused on transaction recording, risk management, and coordination with external parties will potentially have abundant new business opportunities. On the negative side, failure to adapt to changed market conditions may serve to cede the respective marketers' and software services' fields of revenue-generating service to more innovative competitors.

Wholesale Electric Industry Market Participants/Stakeholders

Generators

Economic Impacts: The economic impact on gas-fired generators will either be negligible, in the case of the marginal generator(s) whose variable production costs form the wholesale electric markets' Clearing Price, or beneficial to all other generators (infra marginal generators) in the wholesale electric market whose bid prices are less than the marginal price. This is because pipeline charges for non-ratable service, when they use existing capacity or VMC rates for use of Merchant Capacity will, in both cases, be volumetric (as opposed to fixed) and therefore components of Price Formation processes in the wholesale electric market. The degree of benefit will vary from significant to negligible depending upon heat rate and relative use of non-ratable supply and capacity. For instance, low heat rate, baseload, gas-fired and renewable generators, and battery storage providers will benefit most. Gas-fired intermediate generators will benefit less, while gas-fired peakers that today form the Clearing Price will continue to form the Clearing Price. In addition, to the extent Merchant Capacity is brought into service, the added capacity will assist generators in avoiding ISO penalties for non-performance due to lack of access to transportation/gas delivery capacity. Avoidance of penalties is an economic benefit.

The degree of benefit will vary from significant to negligible depending upon heat rate and relative use of non-ratable supply and capacity.

Market Behavior Impacts: For the most part, the authors do not anticipate changes in market behavior of generators (whether gas-fired or not) in the wholesale markets owing to the introduction of pipeline charges for the provision of non-ratable services other than (for gas-fired generators) identifying the level and timing of such charges on their units in order to incorporate such charges into their hourly "bid to the grid" prices.[37] In any event, enhanced and more transparent price formation and price signals will enhance market efficiency within the electric generator segment.

Business Opportunity Impacts: For generators/electric energy providers generally, the business opportunities are numerous. Ranging from increasing opportunities for substitution of gas-fired

[37] Such prices in both the day-ahead and real-time electric markets.

generation by battery discharge to load-following geothermal generation and/or on-site fuel storage, investments meeting economic thresholds will be developed and deployed accordingly.

Marketers/Brokers

Economic Impacts: For Marketers/Brokers within the wholesale electric market, the economic impacts will parallel those of the generators and distributors to whom they provide outlet or supply. As such while the electric markets' marketers/brokers will have to adapt their transactions, the authors do not anticipate any net positive or negative economic impacts on marketers/brokers solely as a result of pipelines charging volumetric rates for non-ratable service or charging VMC rates for use of Merchant Capacity.

Market Behavior Impacts: For the most part, the authors do not anticipate changes in market behavior of marketers/brokers in the wholesale markets owing to the introduction of pipeline charges for provision of non-ratable services other than identifying the level and timing of such charges on their suppliers' units to incorporate such charges into their hourly "bid to the grid" prices.

Business Opportunity Impacts: Like the wholesale gas market's marketers, the electric market's marketer/brokers will likely see numerous aggregation/disaggregation opportunities in response to adapting to Clearing Price changes. Likewise, those marketers/brokers who do not adapt to such changes may cede the field to adaptive competitors.

Electric Distribution Companies (EDCs)

Economic Impacts: EDCs are likely to be largely unaffected by the proposed rate changes except where they are part of a vertically integrated electric market where marginal prices may be impacted and such prices are flowed through to distributors' energy costs. EDCs in organized wholesale markets are unlikely to be impacted by the proposed pipeline rate changes.

Market Behavior Impacts: EDCs are not anticipated to alter their daily or long-term supply or transmission capacity contracting based on the introduction of non-ratable service charges by pipelines to generators. Neither are EDCs (in vertically integrated electric markets) likely to alter daily supply purchases and related procedures between them and their third-party suppliers. EDCs with a retail sales function to retail customers will generally deal with wholesale price changes the way they do today – as part of periodic cost pass-through proceedings at the state level.

Business Opportunity Impacts: The authors do not anticipate substantial business opportunity impacts (positive or negative) for EDCs.

Electric Transmission Owners

Economic Impacts: Electric Transmission Owners are unlikely to be economically impacted by the introduction by pipelines of rates for non-ratable pipeline delivery services. Given that for over 95% of the time these services are being provided by pipelines currently, the introduction into the energy market of a price for the services provided by pipelines is unlikely to change the manner or level of compensation to owners of electric transmission lines.

Market Behavior Impacts: Again, given that the non-ratable services of pipelines are being provided currently and the proposed change is to charge for them, the authors do not project Transmission Owners to change or face changes to their roles within the electric market. In the organized electric markets, Transmission Owners are compensated by the ISOs which (as discussed earlier) in turn collect revenue from the broad base of those that benefit from the Transmission services being provided by Transmission Owners. In the organized markets the ISOs operate the grid of facilities owned by the Transmission Owners. The only difference in vertically integrated markets is that the EDCs whether in the same corporate entity as the Transmission Owner or a customer of the Transmission Owner compensate the Transmission Owners directly rather than having the ISO be the entity collecting costs from the EDCs (and others) and dispersing those collections to Transmission Owners.

Business Opportunity Impacts: It is conceivable that there may develop some business opportunities under which Transmission Owners may have new opportunities to transmit dispatchable load-following power from new sources of such power (potentially new geothermal or pumped hydro facilities) to the electric markets served by load-following gas-fired generation. This may become especially true if such opportunities become economic and operational substitutes for gas-fired generation served by non-ratable pipeline delivery services. It is also conceivable that, for the vast majority of Transmission owners, the topology of their facilities is such that no such business opportunities will develop.

Independent Grid Operators (ISO/RTO) and Reliability Region Transmission Planners

Economic Impacts: Independent Grid Operators and non-ISO Transmission Planners have member-approved budgets and associated revenue requirements. As such, the ISOs' revenue requirements are not related to the revenues they collect and disburse from the operation of their respective Energy Markets or Capacity Markets. In the author's view, the introduction of pricing for non-ratable services by pipelines serving gas-fired generators will have no economic impact on Grid Operators. Just as current changes in gas prices do not impact Grid Operators revenue requirements, neither should other changes in delivered costs of fuel.

... no economic impact on Grid Operators...

Market Behavior Impacts: Again, given that the non-ratable services of pipelines are being provided currently, and the proposed change is to charge for them, the authors do not project Grid Operators to change or face changes to their roles within the electric market or to their roles in coordinating with pipelines providing service to the electric grid's gas-fired generators.

Business Opportunity Impacts: Independent Grid Operators are not-for-profit entities. As such, they are motivated, not by profit, but by requests for services expressed by the pertinent voting thresholds of their membership boards. It is therefore not anticipated by the authors that the changes to pricing for pipeline services will present business opportunities or threats to Independent Grid Operators.

End-Users

Economic Impacts: All things being equal, end-users consuming electricity will see economic impacts from higher costs flowed through by their suppliers whether they be marketers/brokers or EDCs. The magnitude of those impacts may be lesser or greater than those currently experienced by end-users resulting from volatile natural gas prices. On the other hand, end-users whose electric service is curtailed due to lack of gas-fired generation during periods of extreme weather will likely see a decrease if not elimination of such events should the proposed changes spur investment in additional pipeline capacity and/or operational and competitive substitutes. The off-setting positive economic benefits of fewer blackouts may be perceived as being worth the cost of a more reliable and resilient energy delivery system.

The off-setting positive economic benefits of fewer blackouts may be perceived as being worth the cost of a more reliable and resilient energy delivery system.

Market Behavior Impacts: The authors do not project any pervasive changes in end-user market behavior due to the introduction of charges by pipelines for the provision of the proposed services. Those end-users participating in demand response programs/markets may see more revenue opportunities but given the hourly nature of those opportunities, it is unclear whether end-user participation in demand response will increase.

Business Opportunity Impacts: To the extent an individual or class of end-users pay hourly wholesale energy rates and depending on the level of economic impact on such end-users, on-site installation of battery capacity may be a substitute to incurring elevated electricity prices influenced by pipeline charges for non-ratable service to electric generators.

Electric Industry Technology/Services

Economic Impacts: The authors do not anticipate direct positive or negative economic impacts on electric industry technology or service providers from the introduction of pipeline charges for non-ratable services.

Market Behavior Impacts: Like the authors' view of economic impacts on electric industry technology or service providers from the introduction of pipeline charges for non-ratable services, our view is that there are few, if any, likely changes to this segment's market behaviors.

Business Opportunity Impacts: For the entities in the Technology/Services segment there are projected to be numerous and expansive business opportunity benefits and threats. On the positive side, software services providers focused on transaction recording, risk management, and coordination with external parties will have potentially abundant new business opportunities. On the negative side, failure to adapt to changed market conditions may serve to cede the respective software services' fields of revenue-generating service to more innovative competitors.

Next Steps

The authors recommend that the FERC institute a Notice of Proposed Rule (NOPR). The purpose of such NOPR would be to establish industry-wide mandatory rules. Mandatory and industry-wide rules will prevent competitive distortions arising between pipelines and/or ISOs whose generators in the aggregate are likely served by multiple pipelines.

Such NOPR could propose making a Section 5 finding that the failure by pipelines to charge for non-ratable service leads to discriminatory market results, under-investment in critical facilities, and failure to send actionable price signals to both the electric and gas markets regulated by the FERC.

The NOPR could elicit comments from market participants and stakeholders as to the market benefits of pricing previously unpriced load-following delivery services. The NOPR could also seek comment on whether the proposed maximum Volumetric Load Factor Based rate for use of existing capacity should be set at uniform levels across pipelines or have default maximum percentage load-factor derivatives (i.e., 60% load factor, 50% load factor, etc.).

Additionally, the NOPR could seek comment on whether the rate design for recovering costs of pipeline expansions installed on an at-risk basis to serve gas-fired generator load be uniform, have a default, safe harbor formulation, or be a pipeline-specific VMC rate.

The authors also propose that the Commission seek comment on the best method(s) of identifying existing capacity and associated facilities in order to identify that capacity which, when used, would trigger application of the Volumetric Load-Factor-Based rate.

Alternatively, the FERC could institute a Notice of Inquiry (NOI) in order to request that the industries identify policy questions and considerations in addition to those contained in this White Paper.

Following the Commission's review of NOI submissions, the FERC could proceed with the NOPR.

About the Authors

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As President of Skipping Stone, Greg Lander oversees the firm's natural gas strategy, regulatory advisory, and Capacity Center business unit. Greg is also very much engaged in the mergers and acquisition arena, providing subject matter due diligence.

Generally recognized in the energy industry as a natural gas expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State regulators, arbitration cases, and legal or rate design proceedings on behalf of clients.

As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations, and Triage Subcommittees and has initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)) and NAESB. He is the longest-serving member of the board of Directors for NAESB and prior to that GISB – 30 years.

Greg's initial ideas toward aligning the natural gas and electric markets were published in the landmark whitepaper, Synchronizing Gas & Power Markets, coauthored with Peter Weigand in 2013.

Greg looks forward to engaging stakeholders on these proposed solutions and next steps.

Peter Weigand

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As Chairman and CEO of Skipping Stone, Peter Weigand has provided strategic and implementation planning advisory to numerous global clients across the energy industry, including natural gas, power, demand response, energy technology, hydrogen, and renewable energy.

Peter leads the firm's global business development and engagement delivery in European and Asian markets as well as in North America. Peter has been instrumental in shaping Japan's deregulation of its power market. He has been CEO of four companies in the energy and technology arena, taken one of his companies public, bought and sold over a dozen companies, and been instrumental in the success of many more.

He has direct relationships with several hundred energy market leaders and has performed strategy development for over 100 energy clients, both domestically and internationally.

Pennwell has named Peter as one of the Top 50 most influential people in energy, Ernst & Young has honored him as an Entrepreneur of the Year, and his prior companies have been named to several 'fastest growing' lists, including the Inc. 500. Additionally, Industry Era magazine selected Peter as one of the ten best CEOs of 2019.

Appendix A

Brief History of the Gas Pipeline Market

Until the mid-1980s, natural gas pipelines were merchants, buying all the gas connected to their system and selling all the gas out of their systems. Under Federal regulation the pipeline was required to sell gas to all Local Distribution Company (LDC) buyers in similar geographic localities on its system at the same average price, which was derived from the weighted average price each individual pipeline paid for the gas it bought. Sales contracts were structured around peak daily (i.e., 24 hour) consumption volumes and annual consumption volumes.

During the pipelines-as-merchants period, if a pipeline wanted to expand its system, it requested permission from the regulating federal agency[38] and had to show that there would be demand, as well as the supply to meet that demand well into the future. Once the requested expansion was approved, the costs of the capacity expansion (the capital and operations related costs) were paid for by all customers of the system. In essence, prior to the transition to pipelines-as-transporters-only initiatives, [39] all capital costs to serve sales customers were socialized among all sales customers.

Pipeline Market Restructured from Pipeline-as-Merchant to Pipeline-as-Transportation-Service-Only

At restructuring from a merchant model to a transportation only model, the pipelines' previous firm sales contracts were converted to firm transportation capacity contracts and these legacy contracts were priced similarly for similarly situated customers (a.k.a. shippers). Fundamentally, this restructuring of legacy sales service provided to primarily gas distribution companies (performed at delivery points) involved envisaging an equivalent transportation service performed along route(s) (paths) from receipt point(s) to delivery point(s). Under this service, the firm transportation contracts specify inlet or receipt point(s) and daily receipt capacity as well as outlet or delivery point(s) and daily delivery capacity. A salient feature of these contracts is that there was continued historic reliance on daily gas transportation quantities (i.e., 24-hour volume gas consumption) as a means of allocating capacity and allocating cost of service to rates.

A Quick History of Pipeline Rate Design and How the Past may be Prologue.

When pipeline rates were first designed under what was commonly referred to as "United" rate design, everything was dependent on the annual load factor. Since under United rate design, a customer paid for the pipeline for service only when they used it (i.e., bought gas), the rate was considered purely volumetric. You paid for the pipeline when you used the system but paid nothing for the "*right*" to use

[38] From passage of the Natural Gas Act in 1938 up through mid-1978 the Federal Power Authority (FPA) regulated interstate electric and natural gas markets. After that, as a result of the Natural gas Policy Act, the FPA became the Federal Energy Regulatory Commission (FERC).

[39] That is before the early '80's.

the system. Here, rate design and the load factor of the *system* (not individual customer's load factors) were inextricably linked. Under the United rate design, used when pipelines were merchants, pipelines' sales rates included recovery of both gas and facilities' costs. The imputed load factor of the system was used to ascertain the component of sales rates that recovered the fixed costs of facilities' depreciation, return, operations and maintenance. Added to this fixed cost recovery component would then be the cost of gas and other variable costs like compressor fuel and associated sales-volume related costs.

When the pipelines' annual sales exceeded the volume (i.e., load factor) that rates were designed upon, the pipeline made more money (profit). Likewise, if annual sales volumes were less than the volume that rates were designed upon, the pipeline made less (or no) profit. In this latter situation, the pipeline came in for a rate case to charge higher rates due to the need to recover their fixed costs over lower load factor utilization.

During this era of pipeline rate making, high load factor customers complained that they were bearing a disproportionate share of annual costs and in the process subsidizing low load factor customers.

Over time, rate design changed to where the single sales rate was separated into a demand charge (fixed charge) and commodity charge (variable charge). The fixed charges represented amounts that were designed to recover about 50% of fixed costs and commodity charges that were designed to recover 100% of variable costs and the other 50% of fixed costs. This rate design was generally referred to as "Seaboard" rate design.

Then came Modified Fixed Variable rate design, where 75% or more of fixed costs were collected through demand (fixed) charges with gas costs and the remaining fixed costs were collected in commodity charges.

The current, (i.e., post-restructuring from merchant to transporter-only market structure), rate design is Straight-Fixed-Variable (SFV); where, 100% of all non-variable related charges are collected through demand charges, now referred to as "reservation charges," with the only commodity charges. now referred to as "usage charges," being collected on quantities of gas transported. Under SFV rate design, customers of pipelines (shippers) pay reservation charges to reserve rights to transport gas and, when they go through the process to use their reserved capacity and use that capacity (i.e., schedule gas), they pay usage charges for the quantities actually used/transported.

Appendix B

An Explanation of How Gas-Fired Generators' Heat-Rate Connects the Economics of the Gas Industry's Delivered Cost of Fuel to the Electric Markets' Hourly Price Formation and Hourly Generation Dispatch

In the electric markets, both organized wholesale electric markets and vertically integrated electric markets, generation is accepted into the transmission systems from lowest variable cost to highest variable cost generation required to meet electricity demand.

The variable cost of gas-fired generators is a function of variable fuel and transportation cost required to deliver the gas to the facility and the amount of energy (Dths) required to generate a megawatt hour (MWh) of electrical output. Each Dth is equal to one million British thermal units (MMBtu), one Btu being the amount of energy needed to heat one pound of water by one degree at sea level.

The heat rate of a gas-fired generator is the MMBtu's it takes to generate 1 MWh. The most efficient gas-fired combined cycle generators have heat rates in the 6.5-7.0 MMBtu's per MWh. At that heat rate, and assuming a gas price delivered to the unit is $5/MMBtu, the most efficient gas-fired generators can deliver power to the grid at $35 per MWh (7 MMBtu/MW times $5/MMBtu = $35).

The least efficient gas-fired peaking units have heat rates in the 10-12 MMBtu/MWh. Assuming the peaker is: a) the marginal unit whose MWhs are required to meet demand (i.e., the clearing unit defining the Clearing Price), b) gas-fired, and c) gas prices delivered to the generator are also $5/MMBtu, the peaker, to break-even, might have to bid at least $60 per MWh (12 MMBtu/MW times $5/MMBtu = $60).

In organized wholesale electric markets, the highest *accepted* price per MWh determines the price per MWh that all similarly situated generators (regardless of type) are paid for power produced in that pricing interval. In this simple example, one can see that if all generators are paid the Clearing Price, and the Clearing Price is set by the bid of the gas-fired peaker at $60, the very efficient gas-fired generator has a $25/MWh margin for the period of time that the Clearing Price is $60 ($60 minus $35 = $25).

At the same time, in the same market, a generator with no variable fuel cost such as a wind or solar powered generator, with variable costs in the $1.00 or less per MWh range would generate margins in the $59.00 per MWh range during that same period.

Depending on the physical characteristics of transmission and generation of each grid, and its demand-supply topology, this "One Price" as Clearing Price may: a) have prices into constrained load centers that are higher than the Clearing Price and b) have prices out of constrained generation locations that are lower than the Clearing Price. In short, the intersection of the wholesale gas and wholesale electric markets is where the hourly cost of delivered fuel is converted by heat rate into an hourly power price.

About Skipping Stone

Skipping Stone is an award-winning global energy markets strategy consulting and implementation services firm launched by former energy CEOs.

We work with clients across the diverse, yet intersecting, industry segments within the electric and natural gas marketplace to help clients navigate market changes, capitalize on opportunities, and manage business risks.

For almost three decades, we have assisted over 300 energy clients worldwide with thousands of successful projects and initiatives. **www.SkippingStone.com**

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About Capacity Center

Our Capacity Center business unit is the only complete source of gas pipeline capacity transaction information in the U.S. We continuously monitor 100+ interstate pipelines to deliver timely capacity trading information to our customers.

With a robust historical database of trading and flow data we also provide analytics, compliance auditing, and consulting services with expertise and years of gas market experience unmatched in the industry. **www.capacitycenter.com**

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