BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 13F-0145E

LA PLATA ELECTRIC ASSOCIATION, INC.; EMPIRE ELECTRIC ASSOCIATION, INC.; WHITE RIVER ELECTRIC ASSOCIATION, INC.,

Complainants,

v.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.,

Respondent.

ANSWER TESTIMONY AND EXHIBITS

OF

SAMUEL A. NEWELL

On Behalf of

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

September 10, 2014

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I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A: My name is Dr. Samuel A. Newell. I am a Principal of The Brattle Group, an economic consulting firm with offices in Cambridge, MA; New York, NY; San Francisco, CA; Washington, DC; and London, Madrid, and Rome. My business address is 44 Brattle Street, Cambridge, Massachusetts 02138.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of Tri-State Generation and Transmission Association, Inc.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE AS IT RELATES TO THIS DIRECT TESTIMONY.

A: I am an economist and engineer with 16 years of work experience in the analysis and design of wholesale electricity markets. Much of my recent work has focused on improving the design of wholesale capacity markets so they provide proper price signals to efficiently meet resource adequacy requirements. I also specialize in the related areas of integrated resource planning, demand response programs, generation asset valuation, and transmission planning. I am the author or co-author of numerous reports for independent system operators evaluating their wholesale electricity markets. I have provided testimony before the FERC, several state public utility commissions, and the American Arbitration Association. A full list of my testifying experience is provided in my resume.[1]

[1] *See* Exhibit SAN-1.

I earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology; a M.S. in materials science and engineering from Stanford University; and a B.A. in chemistry and physics from Harvard College.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I have been asked to:

- Review the cost of service study developed by Dr. Blake and adopted with adjustments by Mr. Higgins, evaluating the extent to which the costs that they attributed to peak demand were truly driven by peak demand, and assessing the consistency of their analyses with the economic efficiency principles they describe.
- Provide an opinion on Tri-State's costs of meeting incremental peak demand based on current and foreseeable market conditions.
- Provide an opinion on the portion of Tri-State's embedded cost of service that can be attributed to meeting peak demand versus energy.

Q: PLEASE SUMMARIZE THE MAIN POINTS OF YOUR TESTIMONY.

A: My testimony provides evidence and economic theory to support three key opinions:

- First, Dr. Blake and Mr. Higgins argue that rates should provide accurate price signals to encourage the economically efficient use of resources, but their studies and recommendations are inconsistent with that principle by: (1) not considering current system conditions and associated incremental costs to serve; (2) not accounting for the fact that utilities such as Tri-State incur the substantial capital/fixed cost premium for baseload capacity (over peaking capacity) in order to provide low-cost *energy*; and (3) developing a benchmark rate that recovers demand-related costs based on Member

Systems' monthly non-coincident peak demands instead of their system coincident peak demands which can drive demand-related costs.

- Second, Tri-State's incremental cost of meeting additional peak demand is currently minimal due to the surplus of generation capacity that they and their region has available.
- Third, I adjusted Dr. Blake's and Mr. Higgins's cost of service study by attributing a portion of the fixed costs of baseload generation to accessing low-cost energy rather than meeting peak demand. This results in 34% of Tri-State's expenses being caused by demand, compared to 49% in Dr. Blake's testimony, and 37% of Tri-State's member revenue requirement, compared to 56% in Mr. Higgins's testimony.

II. PRINCIPLES OF EFFICIENT PRICING

Q: WHAT HAVE DR. BLAKE AND MR. HIGGINS SAID ABOUT EFFICIENT PRICING PRINCIPLES?

A: Dr. Blake says that rates should reflect cost causation and provide price signals for the efficient use of resources. He states:

> I regard rates as just and reasonable if each member pays rates that are reasonably correlated to the cost that member imposes on the cooperative as a whole. Second, a cooperative should set rates that send appropriate price signals to the members to encourage the members to efficiently use both energy and the generation and transmission capacity needed to produce and deliver energy. If members use energy and capacity efficiently, the overall cost to provide electricity to the entire cooperative is minimized. Furthermore, ensuring that electricity is priced in a way that reflects the cost

> of providing service to its members promotes its wise and efficient use and promotes reasonable economic development.[2]

Similarly, Mr. Higgins states:

> A just and reasonable rate design should also be economically efficient by sending proper price signals regarding the product that is being consumed by customers….[3]

Q: ARE THEIR ANALYSES AND RECOMMENDATIONS CONSISTENT WITH THE EFFICIENT PRICING PRINCIPLES THEY STATE?

A: No, in three important ways. First, their analyses focus solely on classifying Tri-State's embedded costs without considering the going-forward costs of serving incremental demand under current market conditions. Second, their classification of all capital and fixed costs as "demand-related" does not account for the fact that a portion of baseload generation costs is incurred to access low-cost energy. Third, Mr. Higgins's benchmark rate recovers those costs on a monthly non-coincident peak basis, which bears little relationship to the system coincident peak demand that can drive capacity costs.

Q: HOW DO INCREMENTAL COSTS RELATE TO EFFICIENT PRICES?

A: Prices provide efficient signals only if they reflect forward-looking incremental costs, not costs that have already been incurred. This is because additional consumption affects only forward-looking costs (both variable costs and incremental capital and fixed costs), whereas historical costs and even ongoing costs that were committed to in the past are essentially sunk and will not change if consumption changes. Consumers can make economically efficient consumption decisions by weighing their value of service against

[2] Dr. Martin J. Blake Direct Testimony (hereinafter "Blake Testimony") at 6:3-11.

[3] Kevin C. Higgins Direct Testimony (hereinafter "Higgins Testimony") at 4:1-3.

the incremental costs that depend on their consumption decisions, not the sunk costs which are paid independent of how much they decide to consume. This is a central tenet of economics.[4]

Q: DO COMPLAINING PARTIES' WITNESSES DISCUSS FORWARD-LOOKING MARGINAL COSTS?

Generally, no. In spite of their reference to pricing efficiency principles and Dr. Blake's use of the present tense ("causes" and "imposes") in describing cost causation, they rely on a backward-looking cost analysis. The one instance where Dr. Blake discusses going-forward system conditions directly is in response to Mr. Spiers' statement in deposition that, with Tri-State's capacity surplus, peak demand is not driving capacity needs.[5] Dr. Blake does not dispute the current capacity surplus. But Dr. Blake counters with a generic statement that forecasted demand will drive future capacity investment, without presenting an analysis of when such investment might be needed or how the timing would affect costs, or what those future costs are expected to be. In my view, this misses a key point that peak demand is not currently driving Tri-State's costs, nor will it over the next several years. Thus the "efficient" price on demand would be very low. Dr. Blake almost acknowledges this point when he says, "If all costs were caused solely by the consumption of kWh, Tri-State's approach would have merit."[6]

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[4] Frank, R. H., and B. Bernanke. *Principles of Microeconomics*. 3rd ed. New York: McGraw-Hill, 2006, p. 11.

[5] Blake Testimony at 32:4-14.

[6] Blake Testimony at 29:7-9.

Q: WHY DID YOU SAY DR. BLAKE'S CLASSIFICATION OF HISTORICAL COSTS OVERSTATES PEAK-DRIVEN COSTS?

A: In his analysis of Tri-State's cost of service, Dr. Blake allocated costs to demand, energy, and "other" categories. He allocated all plant-related capital and fixed costs to demand. I disagree with this allocation because it ignores the multiple drivers of such costs — particularly the fact that the incremental capital and fixed costs of baseload generation over peaking generation are undertaken to provide low-cost energy, not to meet peak. As such, Dr. Blake's allocation overstates the historical cost of meeting peak demand. I will explain these distinctions in more detail in Section IV.

Q: YOU ALSO MENTIONED THAT MR. HIGGINS'S BENCHMARK RATE DEVIATES FROM EFFICIENT PRICING PRINCIPLES. CAN YOU EXPLAIN HOW?

A: Mr. Higgins's benchmark rate would recover peak-related costs by applying a demand charge to each Member System's monthly peak demand. This approach bears little relationship to the annual coincident system peak demand that tends to drive capacity costs, a fact that Dr. Blake emphasized.[7]

III. FORWARD-LOOKING MARGINAL COST ANALYSIS

Q: WHAT IS THE OBJECTIVE AND SCOPE OF MARGINAL COST ANALYSIS?

A: The objective of marginal cost analysis is to quantify how much an increment of consumption will increase going-forward costs. To provide a complete answer to that question, all types of costs must be considered, including variable costs of production and incremental capital and fixed costs of capacity and transmission. The analytical focus is on

[7] Blake Testimony at 12:1-17.

how those costs would increase with an increment of consumption of energy in each hour, including peak demands that may affect the total amount of generation capacity needed to reliably serve load. Such analysis requires careful consideration of current and forward-looking system conditions, market conditions, and cost factors.

Q: PLEASE SUMMARIZE YOUR FINDINGS ABOUT TRI-STATE'S MARGINAL COSTS AND COST DRIVERS.

A: The marginal cost of providing an increment of energy consumption is about $35/MWh but varies over time. However, *the incremental capital and fixed costs of meeting an increment of demand at system peak are currently minimal*. This is because Tri-State and the surrounding region face a capacity surplus relative to the reserve margins needed to meet reliability criteria, and that surplus is expected to persist for several years. Therefore, increasing Tri-State's demand by consuming at the system peak causes no need for capacity investment. Incremental demand costs can be expected to rise in about 2019 as load growth consumes the Tri-State (and regional) capacity surplus, and capacity investment decisions become imminent.

Increased consumption may also cause Tri-State to incur higher transmission costs, although transmission costs have many drivers that are not easily amenable to marginal cost analysis, and marginal costs would tend to vary by location. However, I provide an indicative calculation of average incremental transmission costs as a check to see whether such costs might be large enough to explain the high demand-related costs that the Complaining Parties' witnesses present. I have estimated the levelized costs of recent, ongoing, and proposed projects whose purpose is to reliably meet peak load growth to be approximately $34/year per kW of peak load growth on average. I have also estimated that increased demand could increase Tri-State's wheeling charges by approximately $2/month per kW of incremental peak demand.

Q: WHAT DOES "MARGINAL ENERGY COST" REFER TO?

A: The marginal energy cost refers to the incremental cost of serving an incremental kWh of energy consumption in each hour, without considering whether any incremental capital and fixed costs would be needed to reliably serve that consumption consistent with target reserve margins—those are capacity costs, which I will discuss separately. The marginal energy cost is the cost of fuel and variable operating and maintenance costs of serving the next unit of energy. The marginal cost is generally higher than the average production cost, since the lowest variable cost resources are used first, leaving more expensive resources to serve the next unit of consumption. As noted above, the marginal cost is the relevant measure for creating efficient price signals since only the marginal production is at stake when a customer is deciding whether to consume an incremental kWh.

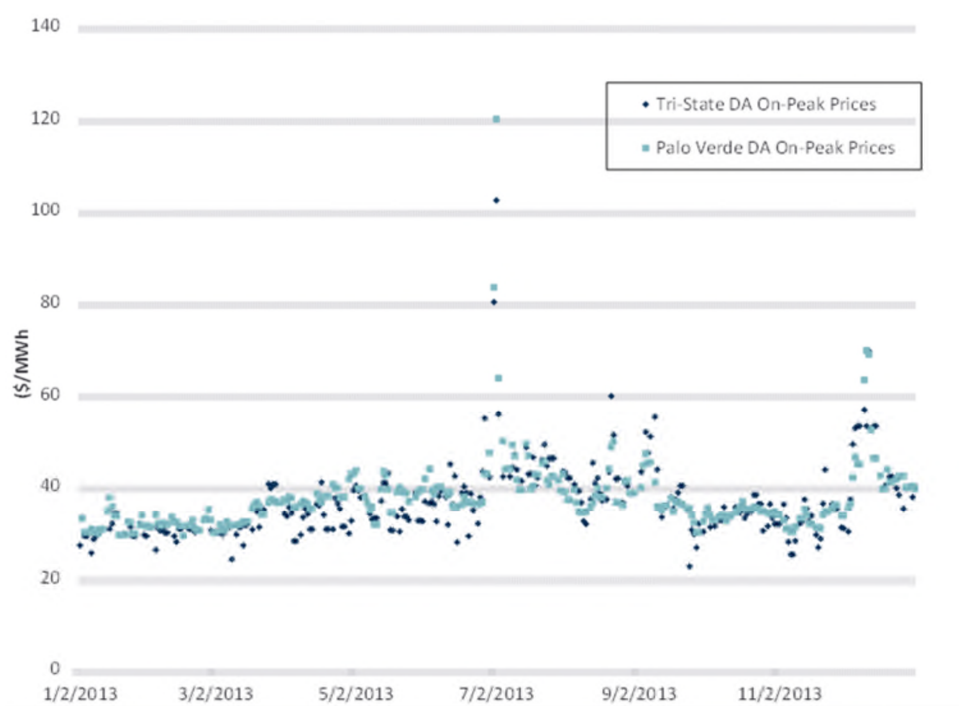
Q: HOW DID YOU ESTIMATE TRI-STATE'S MARGINAL ENERGY COSTS?

A: If Tri-State were an island, I would use Tri-State's own marginal production costs. However, it is not an island. Tri-State traders transact frequently with neighbors who at any moment might have the least-cost supply resource to sell to Tri-State; or Tri-State might have the least-cost generation resource available to meet their needs. Thus the price at which Tri-State can transact best represents the marginal cost or opportunity cost (of lost sales) of serving an incremental kWh on the Tri-State system. To estimate that price, I have analyzed Tri-State's recent transaction prices from 2013 and 2014.

Q: WHAT MARGINAL ENERGY COSTS DID YOU FIND?

A: In both 2013 and 2014, Tri-State realized prices of approximately $38/MWh on average during on-peak hours and $26/MWh during off-peak hours.[8] To provide some sense how these have varied by season, I have plotted the 2013 daily average on-peak prices and off-peak prices in Figure 1 and Figure 2. I do not have data on days without transactions, so I also provide prices at the Palo Verde hub, which somewhat track Tri-State's prices, at least in 2013.

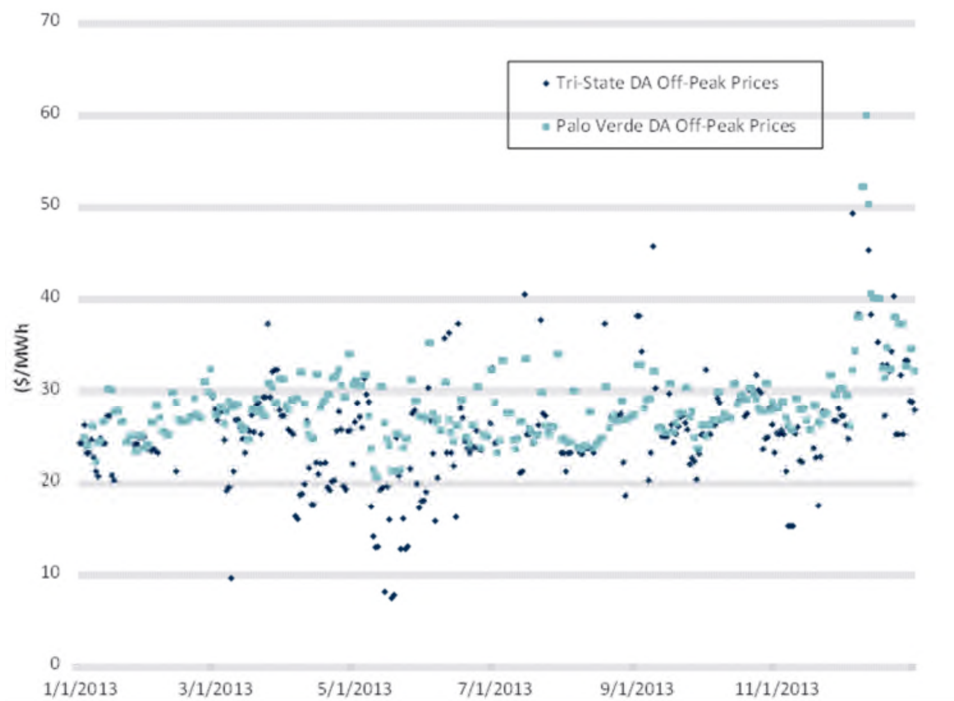
Figure 1: On-Peak Prices



Sources: Tri-State prices provided by Tri-State; Palo Verde prices from Ventyx

8 Annual averages calculated based on the average across all days in which transactions occurred, where each day's price is the volume-weighted daily average of all day-ahead purchases and sales entered into the prior day.

Figure 2: Off-Peak Energy Prices



Sources: Tri-State prices provided by Tri-State; Palo Verde prices from Ventyx

Q: WHAT DETERMINES THE MARGINAL COST OF CAPACITY TO MEET INCREMENTAL PEAK DEMAND?

A: Utilities plan their resources such that they can reliably meet system peak demands under a range of system conditions. Most, including Tri-State, do so by planning enough resources to meet a minimum reserve margin in excess of projected system peak load. When projected supply is expected to fall below that threshold, the utility must build or buy capacity to maintain resource adequacy, and an increment of demand would correspondingly increase the amount procured. In that case, the marginal cost of capacity is the incremental capital and fixed cost of new generation net of any energy cost savings the new generation would provide. But when the system enjoys a capacity surplus, no further capacity is needed, and an incremental kW of demand imposes no additional capacity costs. It does not lead to any increase in investment and it therefore does not impose costs on the system.

Q: WHAT ARE TRI-STATE'S SUPPLY/DEMAND OUTLOOK AND ITS PROSPECTS FOR NEEDING ADDITIONAL CAPACITY?

A: Tri-State plans its resources to meet a resource adequacy requirement of 15%.[9] Its reserve margin is projected to meet or exceed that requirement over the next several years without needing new generation capacity. Tri-State developed a surplus of capacity because it acquired resources in the 2007-08 timeframe in anticipation of robust load growth, and then the economic recession slowed load growth below expectations. Sales agreements helped rationalize the surplus. Over the next several years, several of Tri-State's sales agreements are scheduled to expire, and the capacity associated with those sales agreements will become available to Tri-State. It is my understanding that Tri-State will recover 554 MW of capacity associated with these sales between now and 2021. Recaptured capacity will roughly match or exceed forecasted load growth, obviating the need for investment in new generation for several years. Tri-State's draft 2014 Electric Resource Plan (ERP) Annual Progress Report update projects no need for new generation resources until 2022, as shown in Figure 3.[10] The draft 2014 APR does not specify which type of generation would be built, but the 2013 APR indicated that the next plants constructed would likely be natural

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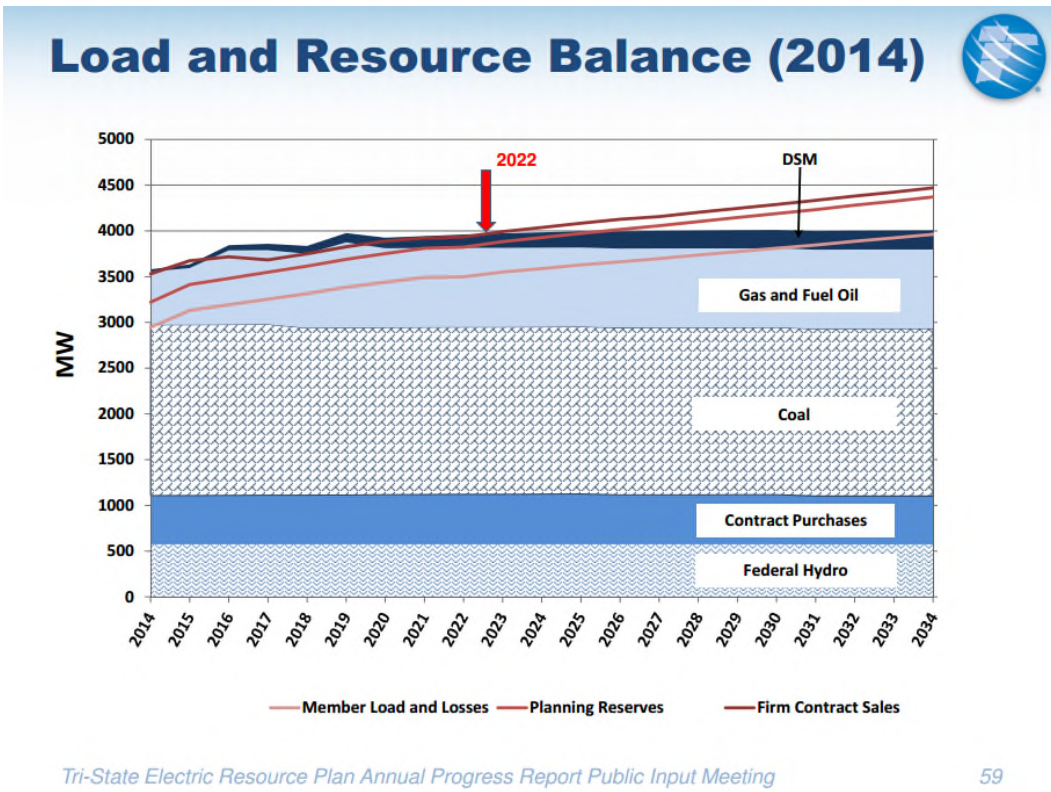
9 *Electric Resource Plan Annual Progress Report* for Tri-State Generation and Transmission Association, Inc. Submitted to: Colorado Public Utilities Commission, October 31, 2013 (hereinafter "2013 APR"), p. 5.

10 Salva, Michael, "Markets, Assessment of Need, Resource Additions Update", in Tri-State G&T, *Electric Resource Plan Annual Progress Report*, presented at Public Input Meeting, August 8, 2014, p. 59 (hereinafter "Draft 2014 APR"), http://www.tsgt.us/ResourcePlanning/documents/Tri-State_2014-ERP-Progress-Report.pdf.

gas-fired.[11] Such a resource takes no more than about three years to develop, so a decision to proceed would have to be made in about 2019.

Figure 3: Load and Resource Balance (2014)



Q: IS THERE ANY CHANCE TRI-STATE COULD NEED NEW GENERATING CAPACITY BEFORE 2022?

A: Yes. The time when additional capacity is needed could change if peak load growth rates change, if more generation retires than currently planned, or if contractual arrangements with other utilities or resource owners change. Recent versions of Tri-State's ERP have revised the year of need from 2020 in the 2010 ERP, to 2023, 2026, and 2028 in the 2011,

[11] 2013 APR, p. 14.

2012, and 2013 updates,[12] respectively, and now back to 2022 in the draft update for 2014.[13] Tri-State also analyzes scenarios in which demand, supply, and environmental drivers vary. In its 2013 update to its high load growth scenario, new capacity was needed as early as 2018.[14] However, Tri-State would not plan according to this currently unlikely scenario unless and until Tri-State finds itself on such a trajectory. Even then, Tri-State could likely buy capacity at a low price from its neighbors, due to regional capacity surpluses.

Q: WHEN WOULD THE REGION NEED NEW CAPACITY?

A: The region is facing similar capacity surpluses according to numerous assessments by the North American Electric Reliability Corporation ("NERC"). NERC's most recent 2014 Summer Assessment shows a reserve margin of 32.7% in the Rocky Mountain Reserve Group ("RMRG"), compared to a reference level of 14.5%, and other neighboring regions also have reserve margins at least 10 percentage points above target.[15] The Western Electricity Coordinating Council ("WECC"), of which Tri-State is a member, provides a longer-term analysis of RMRG and the other regions within the Western Interconnection. It shows a 21% reserve margin in 2014 — less than the NERC summer assessment because it accounts for 1,264 MW of firm capacity exports to other regions.[16] But the RMRG has

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12 *Integrated Resource Plan/Electric Resource Plan* for Tri-State Generation and Transmission Association, Inc. Submitted to: Western Area Power Authority Colorado Public Utilities Commission, November 2010 (hereinafter "2010 ERP"), p. 13; *Electric Resource Plan Annual Progress Report* for Tri-State Generation and Transmission Association, Inc. Submitted to: Colorado Public Utilities Commission, October 31, 2012 (hereinafter "2012 APR"), p. 6; 2013 APR, p. 7.

13 Draft 2014 APR, p. 59.

14 2013 APR, p.13.

15 The North American Electric Reliability Corporation, *2014 Summer Reliability Assessment*, May 2014, p. 30.

16 Western Electricity Coordinating Council, *2013 Power Supply Assessment*, September 23, 2013, with Case 1 and Case 2 resources.

enough net capacity to maintain reserve margins in excess of 18% through 2017. Thereafter, WECC projects sufficient surplus in neighboring sub-regions and enough import capability into the RMRG to maintain reserves in excess of the 14.5% regional target through 2022. WECC projects that the RMRG will be at target by 2023, presumably needing new capacity thereafter (although the analysis does not extend beyond 2023).[17] This timing coincides approximately with Tri-State's own year of need of 2022. Other utilities may need capacity sooner (and yet others later), but they would likely not have to pay very high prices when other utilities and the region as a whole have surplus capacity.

Q: WHAT ARE THE IMPLICATIONS OF TRI-STATE'S SURPLUS CAPACITY PROJECTIONS FOR ITS MARGINAL CAPACITY COSTS OF MEETING PEAK DEMAND?

A: With capacity surpluses projected for the next several years, no new capacity is needed to meet peak demands. An incremental kW of demand today causes no need to build or buy capacity. Thus, the cost to Tri-State of meeting incremental peak demand is very low. The marginal cost of meeting demand is not expected to rise significantly until the 2019-2022 timeframe. 2019 is approximately when an investment decision would have to be made to deliver additional capacity in 2022. At that point, the cost of meeting an increment of demand would rise to the levelized capital plus fixed costs of a peaking generation plant.

[17] *See* WECC's 2013 backup spreadsheets (compared to NERC's 2014 Summer Assessment), located at http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2Fcommittees%2FStandingCommittees%2FPCC%2FLRS%2FShared%20Documents%2FNERC%20Long%20Term%20Reliability%20Assessment%20%28LTRA%29%20Data%20Sheets%2F2013%20Files&FolderCTID=0x012000FA4FA82A1BFBCC4492413F74844D464B&View={3D8A4591-23BB-4BCD-8C40-2E3B34AA2BBC}

Q: DO YOU HAVE ANY TRANSACTION DATA TO SUPPORT YOUR CONCLUSION THAT CAPACITY PRICES SHOULD CURRENTLY BE VERY LOW?

A: There is limited information available from transaction data because Tri-State has executed few capacity transactions recently. As I have explained, both Tri-State and neighboring systems are in surplus. As a result, there is little need or interest for transactions to take place. However, what evidence there is suggests that the value of capacity is very low.

Q: WHAT LIMITED DATA DO YOU HAVE?

A: Tri-State has responded to several requests for proposal ("RFPs") and entered into a few contracts for tolling arrangements over the past few years. Tolling agreements provide the buyer the right to the capacity of a resource and the ability to capture any energy value from operating the plant when its variable cost is less than the prevailing market price for power.

- Tri-State entered a tolling sale of one of its Pyramid peaking units to El Paso Electric for the three summer peak months in 2010.[18] The capacity price was $12.50/kW-month for those three months (encompassing the system peak, when capacity has the most value), amounting to $37.50/kW-year.
- Between 2011 and 2013, Tri-State again offered El Paso tolling agreements on its Pyramid units at prices approximately equivalent to $30 to $45 per kW-year (for June-August in the 2011 and 2012 offers, and July-August in the

[18] Contract No. TS-10-0032: Power Purchase Transaction Confirmation between Tri-State Generation and Transmission Association, Inc. and El Paso Electric Company, April 2010.

2013 offer). El Paso rejected all of these offers, suggesting that the price was too high or they found a lower-priced alternative.[19]

- Tri-State rejected an offer from Shell in June 2012 for a tolling agreement on one of Tri-State's Pyramid units for $1.25/kW-month, equivalent to $15 per kW-year.[20] This suggests that Tri-State believed the value exceeded $15 per kW-year.

These data points are sparse, but they indicate a market price of peaking resources above $15 and below $45 per kW-year between 2010 and 2013. Only a portion of that price should be attributed to capacity, however. The rest can be attributed to energy option value, reflecting the ability to capture net revenues whenever power prices exceed variable operating costs. Thus, $45/kW-year could be considered an upper bound on the value of capacity, with the caveat that it is based on very few transactions.

Q: HOW DOES THIS UPPER BOUND COMPARE TO THE CAPACITY PRICES SUGGESTED BY THE COMPLAINING PARTIES' WITNESSES?

A: This upper bound is less than a sixth of what the witnesses for the Complaining Parties suggest. In his derivation of an alternative rate design, Mr. Higgins calculates a demand charge that would collect *in each month of the year*, including all of the non-summer months that do not contain the system peak demand.[21] This amounts to

[19] Tri-State Generation and Transmission, Inc. Response to El Paso Electric Company, *Term 1 Request for Proposals*, June 2012-August 2012. February 2, 2012; Tri-State Generation and Transmission, Inc. Response to El Paso Electric Company, *Term 2 Request for Proposals*, June 2013-August 2013. February 24, 2012; Tri-State Generation and Transmission, Inc. Option A (Day-Ahead) Response to El Paso Electric Company, *Request for Proposal* Terms July 2011-August 2011. June 8, 2011. p. 3; Tri-State Generation and Transmission, Inc. Option B (Real-Time) Response to El Paso Electric Company, *Request for Proposal* Terms July 2011-August 2011. June 8, 2011.

[20] Shell Energy North America (US), L.P. (Shell Energy), *Pyramid Unit 4 LM 6000 Tolling Agreement October 2014-September 2016,* Draft Term Sheet, June 8, 2012.

[21] Higgins Direct Testimony, CONFIDENTIAL Exhibit KCH-5, p. 4.

per kW-year for a kW of demand across the year.[22] Excluding transmission-related costs, which I address separately below, Mr. Higgins's estimates amount to approximately per kW-year of capacity costs.

Q: YOU MENTIONED THAT THE EFFICIENT CAPACITY PRICE SHOULD RISE TO THE LEVELIZED COST OF A NEW PEAKING PLANT WHEN NEW CAPACITY NEEDS BECOME IMMINENT. WHY A PEAKING PLANT?

A: If the only goal of resource planning were to meet peak load, a peaking plant would always be the lowest-cost new generation resource for meeting it because it has the lowest capital and ongoing fixed costs relative to other types of plants (when lower capital cost options, such as purchases, plant uprates, and demand response are not available). Other plants with higher capital costs and lower variable costs might be more economic overall, but only if the incremental energy cost savings is enough to justify the additional capital costs over and above the capital costs of a peaking plant, such that their net capacity cost is less than that of a peaking plant.

Q: HAVE YOU ESTIMATED THE LEVELIZED COST OF A NEW PEAKING PLANT FOR TRI-STATE?

A: Yes. I started with the fixed operating and maintenance (O&M) cost estimates that I understand Tri-State uses for planning purposes when evaluating the lowest capital cost generation resource available, a new 209 MW frame-type gas-fired combustion turbine. I then translated the capital cost into a level-real equivalent, recognizing that the plant will continue to serve load over its economic life. (Another way to think about it is that, assuming prices stay at the levelized cost on a long-term average

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[22] The annual cost per kW of annual peak demand would be less if associated with lower demands in non-peak months.

basis, the plant would earn enough in later years to pay for all but the first year of levelized costs; so the incremental cost imposed by a kW of demand today is just the first year of levelized costs, and not the full cost of the plant). To do so, I calculated the real annuity equivalent of assuming Tri-State's 5.31% cost of capital, a zero tax rate, and a conservatively short 20-year economic life assumption. I then added the annual fixed O&M costs to arrive at a total levelized cost of This is before deducting the energy value of a peaker, which I have not estimated but could be positive if the new peaker allows Tri-State to avoid dispatching or having to buy energy at a price above the peaker's dispatch cost.

Q: HAVE YOU COMPARED YOUR ESTIMATED SHORT-TERM AND LONG-TERM PRICES TO THOSE IN ORGANIZED ELECTRICITY MARKETS THAT HAVE AN EXPLICIT CAPACITY PRICE?

A: Yes. I compared my estimates to organized markets, since they are structured to provide marginal cost-based price signals that promote economic efficiency. I focused on PJM Interconnection, ISO New England (ISO-NE), the New York ISO (NYISO), and the Midcontinent Independent System Operator (MISO), all of which administer auctions for generation capacity separately from energy. In these markets, it is possible to observe transparent capacity prices and to see how they relate to reserve margins. I did not consider other organized markets that lack a transparent capacity price: the Southwest Power Pool (SPP) does not administer capacity auctions; California has a bilateral market for resource adequacy with limited price transparency; and unlike Tri-State and the rest of the U.S., the Electric Reliability Council of Texas (ERCOT) does not have a capacity market.

Q: WHAT DID YOU FIND ABOUT CAPACITY PRICES IN THOSE MARKETS?

A: I made three relevant observations. First, capacity prices are very low in surplus capacity conditions similar to Tri-State's current conditions. Second, capacity prices rise when surpluses erode and new capacity is needed. And third, even then, capacity prices are not as high as Complaining Parties suggest, even though several factors should make capacity prices higher in those particular markets.

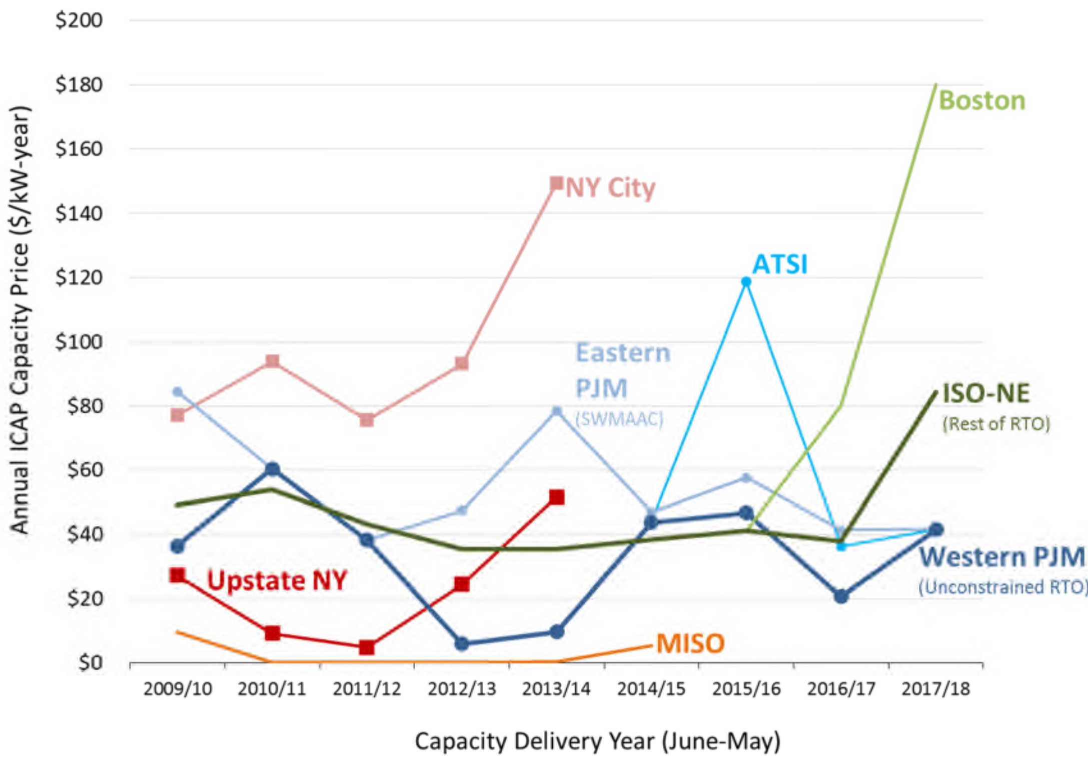
Q: WHAT IS THE PRICE OF CAPACITY UNDER SURPLUS CAPACITY CONDITIONS?

A: The price of capacity under surplus conditions varies by market and over time, partly because the degree of surplus varies, but also because each market has its own idiosyncrasies affecting prices. For example, ISO-NE has experienced capacity surpluses of as much as 14% above target reserve margin, but the price did not fall below $36/kW-year because of a price floor that stakeholders had agreed upon. In the unconstrained portion of PJM that is west and south of the eastern load pockets, surplus capacity has kept prices low, but prices have varied from about $5/kW-year to $60/kW-year as market rules changed regarding the treatment of transmission constraints and the inclusion of demand response in the auctions. Upstate New York has enjoyed surplus capacity, keeping prices below about $55/kW-year. There and in PJM, the price follows administratively-priced demand curves that mitigate price volatility (including price collapse in surplus conditions) in order to reduce risks for merchant generation investors and consumers. These patterns are shown in Figure 4 below. MISO has had the lowest capacity prices (near zero) because of a capacity surplus combined with the lack of a volatility-mitigating demand curve or price floor.

Q: WHICH MARKETS HAVE EXPERIENCED TIGHTER RESERVE MARGINS AND CORRESPONDINGLY HIGHER CAPACITY PRICES?

Few markets have experienced such conditions because most areas have only slowly been growing and retiring out of a surplus left over from excess construction in the early 2000's followed by the economic recession. However, a few areas have developed tighter reserve margins. Within PJM, the ATSI sub-area around Cleveland experienced retirements, bringing reserves to just 1% above the target reserve margin for the 2015/16 delivery year, and prices reached the Net Cost of New Entry pricing benchmark for that area, at about $120/kW-year. In ISO-NE's most recent capacity auction, Boston would have been below the target reserve margin but for a new entrant, and an "Insufficient Competition" rule led to an administrative price at the price cap of about $180/kW-year. In NYISO's most recent auction for 2014, the New York City area approached the target reserve margin, and prices there rose to $140/kW-year. Note that even these prices that reflect scarcity (rather than surplus) have capacity prices below the suggested by Complaining Parties' witnesses for "production demand" (*i.e.*, capacity) costs.

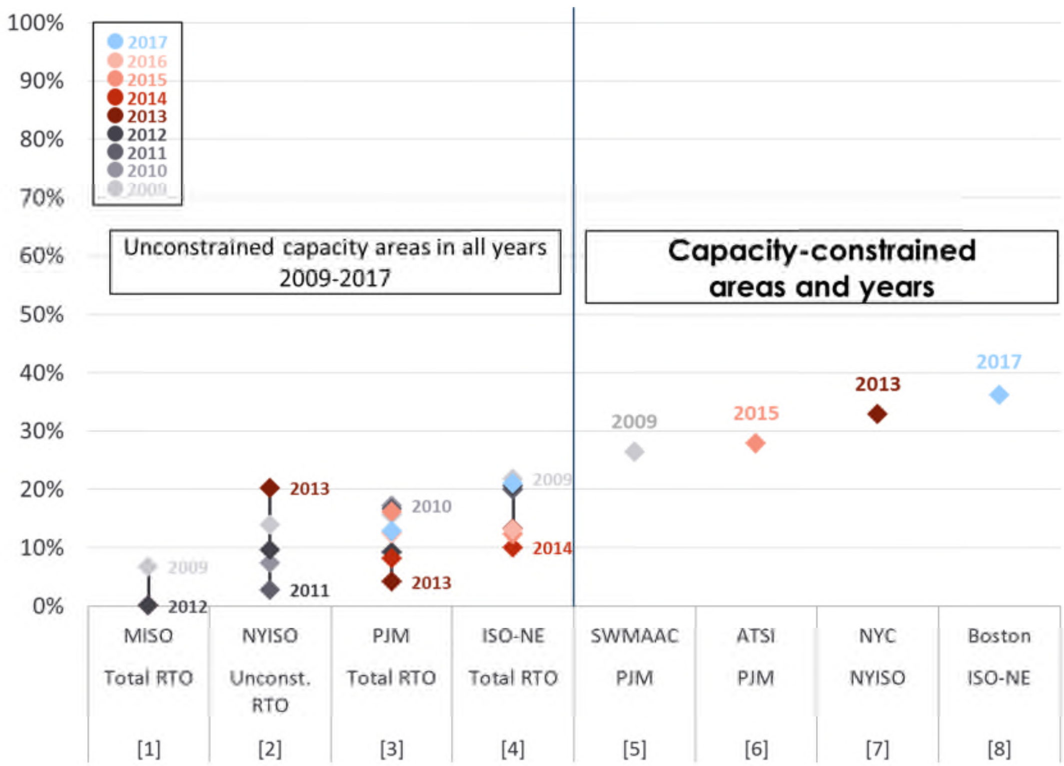
Figure 4: Annual Capacity Price by Capacity Delivery Year



Q: HOW HIGH ARE ORGANIZED MARKETS' CAPACITY PRICES COMPARED TO THEIR ENERGY COSTS?

A: Under surplus capacity conditions, capacity costs are much smaller, accounting for only 0 to 22% of customers total generation costs. The left side of Figure 5 shows cost data for the organized capacity markets during periods of surplus, by plotting annual customer capacity costs as a percentage of total energy plus capacity costs. The right side of the figure shows how capacity costs have increased in the few instances of tighter reserve margins mentioned above. There, capacity prices have risen to 26-36% of total generation costs. I note that even these relatively high percentages reflecting tight market conditions are less than the 46% of production costs Mr. Higgins would have Tri-State charge on a demand basis during its current surplus conditions.[23]

Figure 5: Capacity Costs as a Percentage of Total Production-Related Costs



Q: WHY ARE THESE PRICES LOWER THAN THE COMPLAINING PARTIES SUGGEST FOR TRI-STATE?

A: Prices have remained below the cost of new generation partly because of pre-existing capacity surpluses followed by the entry of demand response (DR) and other low-cost resources. And even when market prices rise and new generation becomes economic, the markets recognize that the marginal economic cost of serving an increment of peak demand is not the full capital cost of a new plant, especially not a coal plant. Long-term average

23 *See* just the production line items from Mr. Higgins's testimony, shown in Table 2 below.

prices may be even lower than the full capital cost of a new peaking plant, since energy margins may provide some of the capital recovery, with capacity prices only covering the remaining capital cost. However, prices may sometimes exceed the levelized cost of peaking generation I estimated for Tri-State, for a few reasons: capital costs are higher in space-constrained and environmentally-constrained locations, such as Boston and New York City; prices fluctuate in organized markets, sometimes falling and sometimes rising to scarcity levels that temporarily exceed long-term average equilibrium prices; such price fluctuations expose price-setting merchant generation investors to greater risk than a traditionally-regulated utility or a co-op with captive customers paying rates that always recover revenue requirements, and this raises their cost of capital; and price-setting merchant generators do not have access to tax-free debt financing like Tri-State does.

Q: APART FROM GENERATION CAPACITY NEEDS, DID YOU ALSO CONSIDER HOW TRANSMISSION NEEDS MIGHT CONTRIBUTE TO TRI-STATE'S COST OF SERVING AN INCREMENTAL KW OF DEMAND?

A: Incremental demand does not "cause" incremental transmission costs in the same way that it causes incremental generation capacity costs because the need for new transmission capacity depends on the location of the demand increment and the location of the new generation capacity. Nevertheless, to see whether incremental transmission costs might somehow close the gap between the demand-related costs I find and the demand-related costs the Complaining Parties' witnesses suggest, I estimated the *average* transmission costs Tri-State is spending to accommodate incremental demand.

Q: HOW DID YOU ANALYZE TRANSMISSION INVESTMENT COSTS ASSOCIATED WITH INCREMENTAL PEAK DEMAND?

A: I reviewed Tri-State's major transmission projects with actual/planned completion dates between 2007 and 2021. Some projects are built primarily to reliably meet growing peak demand; others to enhance reliability for existing load; others to reduce wheeling charges paid to neighboring utilities; others to integrate new renewable resources to meet renewable energy requirements; and many are built for a combination of reasons. Based on discussions with Tri-State staff, I identified those projects that are primarily or partially driven by peak demand growth. The cumulative cost of such projects is $346 million over 14 years (after adjusting for an assumed 3% escalation rate), or $25 million per year.

Q: WHAT DO THESE ANNUAL TRANSMISSION INVESTMENT COSTS IMPLY ABOUT THE MARGINAL COSTS OF MEETING PEAK DEMAND?

A: Transmission costs are not typically analyzed on a marginal cost basis, except for marginal re-dispatch costs associated with transmission constraints, as embedded in locational marginal prices. Indeed, transmission demands are locational in nature, depending on where the load is relative to the generation, and the degree of congestion on the lines in between. Some loads may cause investment and others could relieve it. Hence, an "average" incremental transmission cost over the system as a whole is therefore likely to have little or no relevance for efficient prices. Moreover, transmission projects are lumpy in nature and may be undertaken for a variety of reasons, so current projects may not be a good indicator of costs that further demand additions will cause.

Nevertheless, I have calculated Tri-State's average costs of peak demand growth driven transmission projects. Again, the purpose of this calculation is to assess the order of magnitude of transmission costs to see whether they might somehow close the gap between the demand-related costs I find, and the demand-related costs Complaining Parties' witnesses suggest.

Q: WHAT AVERAGE MARGINAL TRANSMISSION COSTS DID YOU FIND?

A: I first translated Tri-State's $25 million average annual capital expenditures into a levelized cost by applying a 4.3% real capital charge rate (reflecting a 5.31% cost of capital, zero tax rate, and 40-year project life) plus 3% for associated O&M costs. That produced levelized costs of $2.1 million per year. Next, I divided by Tri-State's peak load growth rate of about 54 MW per year.[24] The resulting average incremental cost was $34/kW-year. This is conservatively high to the extent that peak-driven transmission projects also have secondary rationales and benefits.

Q: HOW DID YOU ESTIMATE INCREMENTAL WHEELING COSTS?

A: It is typically difficult to uniformly estimate the impact of additional peak demand on wheeling charges. Some wheeling charges depend directly on monthly peak loads, while others depend on short-term or long-term usage of the transmission system, and usage varies with specific circumstances. The impact could be positive or negative, depending on where the load is located, and the magnitude depends on the correlation between Tri-State system peak and the system peak of the neighboring utility. Nevertheless, I estimate an average impact as a rough indicator of marginal costs, assuming incremental load would increase Tri-State's wheeling charges proportionally.

Tri-State pays about $57 million per year to use other utilities' transmission systems.[25] I understand the majority of these costs are associated with Network Integrated Service Agreements, where neighboring utilities charge Tri-State for its monthly peak demands

[24] Draft 2014 APR.

[25] TS375-0000592 Tri-State's Approved 2013 Operating/Cost of Service Budget, p. 20.

coincident with the selling utility's own monthly system peak loads. Thus, if Tri-State's load increases, wheeling charges can increase. I estimated Tri-State's increased charges associated with 1 kW of increased monthly demand as follows: I assumed a 1 kW increase in monthly demand, which is roughly a increase in Tri-State demand,[26] increases the demand for transmission on other systems by If that increases the current $57 million annual wheeling charges by Tri-State would pay month. These costs would actually be incurred on demand at the time of the other system's monthly peaks, but I assume they would apply to Tri-State's monthly peaks, for simplicity.

As noted above, this calculation may not precisely inform efficient pricing, but it at least indicates whether the potential cost is likely to be large enough to merit a more detailed approach. Based on a month rough estimate, more precision is unlikely to fundamentally change the assessment of Tri-State's marginal costs.

IV. REVIEW OF COMPLAINING PARTIES' WITNESSES' COST OF SERVICE ALLOCATIONS

Q: PLEASE DESCRIBE THE COMPLAINING PARTIES' WITNESSES' COST OF SERVICE STUDY.

A: In his testimony, Dr. Blake asserts that, "A cost of service study that functionally assigns and classifies the costs included in Tri-State's revenue requirement is the proper basis for developing wholesale rates that accurately reflect the cost of providing service to Tri-State's members."[27] His study analyzes the components of Tri-State's revenue requirements, applying his judgments for classifying each component as "energy-related"

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[26] TSCO0001790 Highly Confidential Spreadsheets, June 1, 2012.

[27] Blake Testimony at 2:20-22.

or "demand-related" or "other." He concludes that 49% of Tri-State's costs are demand-related and 51% are energy-related.[28] Mr. Higgins adopts Dr. Blake's analysis then adjusts for changes in non-member revenues and other factors, resulting in classifying 56% of Tri-State's revenue requirement as demand-related and 44% as energy-related.

Q: DO YOU AGREE WITH HOW DR. BLAKE'S STUDY IDENTIFIES COSTS AS DEMAND-RELATED?

A: No. Dr. Blake overstated the amount of generation capital and fixed costs attributable to peak demand. A portion of Tri-State's capital and fixed costs was committed to for reasons other than meeting the peak, yet Dr. Blake assigns 100% of these costs to demand. If Tri-State had been concerned only with meeting peak demand, it would have built only combustion turbines.[29] But much of Tri-State's fleet is coal-fired, which cost substantially more than combustion turbines on a per-kW basis. Tri-State committed the incremental capital and fixed O&M costs to gain access to low-cost energy.[30] Even some of Tri-State's gas-fired capacity was built or acquired for reasons other than meeting peak. I understand from Tri-State that the JM Shafer plant, for example, was acquired in part because of its low heat rate and its operational flexibility for accommodating intermittent wind generation.[31]

Q: DOES DR. BLAKE RECOGNIZE THE DISTINCTION BETWEEN CHOOSING TO BUILD BASELOAD CAPACITY AND PEAKING CAPACITY?

A: Yes, he does. He states:

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28 Blake Testimony at 3:4-5 and 18:15.

29 *See* Mr. Fitzgibbon's Answer Testimony at 9:9-14.

30 *See* Mr. Walter's Answer Testimony at p. 18:23-19:4.

31 Mr. Walter's testimony at p. 18:4-15.

> It is the need to meet forecasted customer peak demands that drives Tri-State's decisions regarding the amount of generation and transmission plant that it needs to construct or acquire. Thus, it is peak demand that causes these costs to be incurred. Once the decision has been made whether additional generation is needed other factors such as the cost per installed kW of the various types of generation, generator heat rates, the BTU content of fuels, and the price per BTU of various fuels that help to determine the type of generation that is the least expensive for meeting member needs.[32]

And in a separate proceeding before this Commission, he has gone further to suggest that attributing some of the capital/fixed generation costs to average demand may be appropriate unless all of the capacity is gas-fired (which it is not in Tri-State's case):

> In a utility's system planning process, the <u>amount</u> of capacity that a utility constructs or purchases to meet customer needs is driven by system coincident peak demand. The <u>type</u> of capacity is determined based on the relative capital and energy cost characteristics of the different generating technologies, with different types of generating technologies used to develop a least cost resource mix for meeting customer needs. It is because of the different <u>types</u> of generating capacity used to meet customer needs that some Commissions have justified the use of an average and excess demand approach for classifying and allocating the costs of production plant. However, in this proceeding, it is recognized that Black Hills generation fleet consists almost exclusively of natural gas generating capacity, i.e. the generation plant is basically all the

[32] Complaining Parties' Responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, *Interrogatory 3*-15, p. 19, attached as Exhibit SAN-2.

same type. (England, p. 3, lines 16-19) Thus, it is not necessary to use an average and excess approach for recognizing the different types of generators in Black Hills' resource mix.[33]

Q: DOES DR. BLAKE DISTINGUISH BETWEEN TYPES OF GENERATION CAPACITY IN HIS COST OF SERVICE STUDY IN THIS PROCEEDING?

A: No. In spite of Tri-State having a variety of resources, including a large amount of baseload coal-fired generation (unlike Black Hills Colorado), Dr. Blake treats all generation the same in this case. He attributes all capital and fixed costs of even the baseload coal-fired generation to peak demand, without regard to the factors he lists in his response to Interrogatory 3-15. His approach does not reflect the fact that a baseload unit's significantly higher capital and fixed costs relative to a peaker were incurred in order to reduce the cost of energy production.

Q: HAVE YOU PREPARED AN ANALYSIS THAT DOES ACCOUNT FOR THE MULTIPLE DRIVERS OF HISTORICAL COMMITMENTS TO CAPITAL AND FIXED COSTS?

A: Yes. I have modified Dr. Blake's and Mr. Higgins's analyses, taking into consideration the multiple drivers of historical commitments to capital and fixed costs. As a result, a proportion of capacity-related costs which Dr. Blake classified as entirely attributable to "production demand" should be allocated partly to "production demand" and partly to "production energy."

Other than allocating some of the capacity-related costs to energy, I have not made any other changes to the cost of service analysis prepared by Dr. Blake. I started from Dr.

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[33] Cross-Answer Testimony and Exhibits of Dr. Martin J. Blake on Behalf of The Board of Water Works Of Pueblo, Colorado and The Fountain Valley Authority at 9:24 and 10:6, attached as Exhibit SAN-3.

Blake's analysis rather than preparing my own independent bottom-up analysis in order to focus on the most significant issue with which I disagree, namely Dr. Blake's allocation of 100% of capital/fixed generation costs to demand. I have not attempted to review every step of Dr. Blake's analysis, nor do I necessarily agree with all other aspects of his analysis.

Q: WHAT ARE YOUR CONCLUSIONS BASED ON APPLICATION OF THIS METHODOLOGY?

A: The first part of my analysis involves a re-allocation of expenses attributed to production in Dr. Blake's cost of service study. Whereas Dr. Blake found 51% of Tri-State's expenses to be attributable to energy and 49% to demand, I find through re-working of his analysis that 66% of expenses are attributable to energy and 34% are attributable to demand. Table 1a and 1b summarize my results and those of Dr. Blake.

Table 1a: Blake Cost of Service Study Allocations

	Amounts ($m) assigned to		
	Demand	Energy	Total
Production ($m)	374.1	552.4	926.5
Transmission ($m)	162.4	0.0	162.4
Distribution ($m)	3.7	0.0	3.7
Customer ($m)	0.0	0.0	0.0
Total ($m)	540.2	552.4	1,092.6
Total (%)	49.4%	50.6%	100.0%

Source: Exhibit MJB-4, Proceeding No. 13F-0145E, produced as MJB-4.xls.

Table 1b: Newell Cost of Service Study Allocations

	Amounts ($m) assigned to Demand	Energy	Total
Production ($m)	210.9	715.6	926.5
Transmission ($m)	162.4	0.0	162.4
Distribution ($m)	3.7	0.0	3.7
Customer ($m)	0.0	0.0	0.0
Total ($m)	377.0	715.6	1,092.6
Total (%)	35%	65%	100.0%
Re-allocation relative to Blake ($m)	(163.2)	163.2	

The second part of my analysis involves reviewing Mr. Higgins's analysis and reflecting the same adjustment — moving part of the capacity-related costs to energy — in Mr. Higgins's calculations. Mr. Higgins's analysis used the results of Dr. Blake's analysis as an input. Other than adjusting the figures Mr. Higgins relied upon from Dr. Blake's study, the only change I made to Mr. Higgins's analysis was to the allocation of non-member sales revenue, as I describe below.[34] While Mr. Higgins ultimately allocated 56% of Tri-State's total revenue requirement to demand and 44% to energy, I find that demand and energy account for 37% and 63%, of Tri-State's revenue requirement, respectively. Table 2 summarizes my results and compares them to those of Mr. Higgins.

[34] While Table 2b shows that the dollar amounts of the allocation of margin and the 4.9% increase is different in my analysis than in Mr. Higgins's, this difference is not due to a change in methodology, but rather is a consequence of the modifications I made to the figures Mr. Higgins took from Dr. Blake's analysis.

Table 2a: Higgins Revenue-Requirement Allocations

	KCH-5 ($m)	Margin ($m)	4.9% increase ($m)	Reduction for non-member sales ($m)	Final cost of service allocation ($m)	(%)
"Expenses"						
Production Demand						
Transmission Demand						
Production Energy						
Distribution Demand						
Total "expenses"						
Assigned to demand						
Assigned to energy						
Total "expenses"						

Source: Confidential Exhibit KCH-5, Proceeding No. 13F-0145E, produced as CONFIDENTIAL RECA013618.XLSX.

Table 2b: Newell Revenue-Requirement Allocations

	KCH-5 ($m)	Re-allocation relative to Blake ($m)	Margin ($m)	4.9% increase ($m)	Reduction for non-member sales ($m)	Final cost of service allocation ($m)	(%)
"Expenses"							
Production Demand							
Transmission Demand							
Production Energy							
Distribution Demand							
Total "expenses"							
Assigned to demand							
Assigned to energy							
Total "expenses"							

Notes: Costs allocated as per Table 1b; return on rate base ("margin") allocated in the same proportions as net rate base; non-member sales deducted from each expense category proportionally after prior adjustments.

As I did with Dr. Blake, I based my analysis on that of Mr. Higgins in order to reduce the number of issues in dispute and to focus on the key points that are relevant to this proceeding. I do not necessarily agree with all other aspects of Mr. Higgins's analysis.

Q: WHICH COMPONENTS OF THE COMPLAINING PARTIES' COST OF SERVICE STUDY DO YOU AGREE WITH, AND WHAT STARTING POINT DO THEY PROVIDE FOR YOUR ANALYSIS?

A: Dr. Blake's disaggregation of Tri-State's expenses includes $374.1 million of expenses attributable to production demand, $162.4 million attributable to transmission demand, $552.4 million attributable to production energy, and $3.7 million attributable to distribution demand, shown in Table 1a above. I do not contest his allocation of costs in the transmission demand and distribution demand categories.

Q: HOW DID YOU IDENTIFY THE PORTION OF COSTS THAT DR. BLAKE ALLOCATED TO DEMAND THAT SHOULD INSTEAD BE ALLOCATED TO ENERGY?

A: Dr. Blake allocates all capital and fixed costs of production to demand. Dr. Blake's analysis ignores the fact that many of Tri-State's decisions to add capacity reflected a desire to minimize the total cost of providing baseload power rather than simply the need to meet additional peak demand. If this were not the case, Tri-State would have installed more peaking capacity, which is cheap to build but expensive to operate.

My analysis proceeds by estimating, for each major cost component that Dr. Blake allocated to production demand, what costs Tri-State would have incurred if it had installed peaking capacity. I then compare this amount (on a per MW basis) to the amount that Tri-State actually incurred. The "excess" capital and fixed costs that Tri-State actually incurred to minimize its costs of producing baseload energy I allocate to energy.

I conservatively treat Tri-State's transmission O&M expenses as driven entirely by system coincident peak demand, since the transmission system is generally sized to meet peak loads and to transmit the output of generation plants that are also sized to meet peak load.

This is conservatively high because some portion of the historical transmission capital costs may have been undertaken for reasons other than meeting system peak (*e.g.*, to enable lower energy dispatch costs from baseload plants). However, I do not have a straightforward method for parsing historical transmission costs, so I conservatively attribute them all to system peak demand. I also do not have any basis on which to re-allocate distribution costs, so I attributed these costs to system peak demand as well.

Q: WHICH SUB-CATEGORIES OF PRODUCTION EXPENSES HAVE YOU ALLOCATED DIFFERENTLY FROM DR. BLAKE?

A: Dr. Blake allocated certain expense items 100% to production demand (*e.g.*, depreciation) and certain expense items 100% to energy (*e.g.*, fuel). He split other expense items between production demand and production energy in proportion to the total amounts across the line items he had already allocated. I took a similar approach but, for all of the line items that Dr. Blake allocated 100% to production demand, I considered whether Tri-State would have incurred 100% of those costs if it had been attempting to meet increases in demand at lowest cost without optimizing its system to produce cheaper baseload energy. I allocated certain O&M categories, depreciation, and rent (lease) expenses in this way. I agree with Dr. Blake's allocation of 100% of fuel costs to energy.

Q: HOW MUCH OF TRI-STATE'S PRODUCTION OPERATION AND MAINTENANCE EXPENSES DID YOU RE-ALLOCATE IN THIS WAY?

A: I identified $187.8 million of production expense in Dr. Blake's analysis which needed to be allocated in this way, taking into account the multiple drivers of historical commitments to capital and fixed costs. I determined how this amount should be allocated by first calculating the split between fixed and variable components of Tri-State's production O&M expenses and then calculating which portion of the fixed O&M should be attributed to production energy rather than to production demand (variable O&M is naturally attributed entirely to production energy). I calculated Tri-State's variable O&M for 2012 using net generation as reported on a plant-specific basis in Tri-State's 2012 RUS form[35] and plant-specific variable O&M rates provided by Tri-State.[36]

I then assigned the remaining (*i.e.,* fixed) O&M expenses between the energy and demand cost components according to plant type. I calculated fixed O&M in $/kW-year for each type of plant (baseload, intermediate, peaking). I attributed all fixed O&M expenses on peaking plants to production demand. For Tri-State's baseload and intermediate plants, I allocated to production energy all fixed O&M expenses in excess of what those expenses would be on a peaking plant of equal size.

The result of this methodology is that I allocated 90% of the $187.8 million to energy and 10% to demand. In contrast, Dr. Blake allocated these amounts approximately equally between demand and energy.

Q: PLEASE EXPLAIN YOUR TREATMENT OF PRODUCTION-RELATED DEPRECIATION EXPENSES.

A: Dr. Blake assigned all depreciation expenses to the production demand cost category. However, I treat depreciation expenses similarly to fixed O&M expenses as described above. That is, I account for there having been multiple drivers of Tri-State's historical commitments to capital and fixed costs by calculating depreciation on each baseload plant in excess of what depreciation there would have been on a peaking plant of the same size and similar age and attributing that excess to production energy.

35 Tri-State Generation and Transmission Association, Inc., *RUS Financial and Operating Report Electric Power* Supply, December 31, 2012, attached as Exhibit SAN-4.

36 These variable O&M rates are used for daily dispatch decision-making, budgeting, and long-term modeling of Tri-State's system for resource planning purposes.

To calculate these "excess depreciation" amounts, I first isolated the portion of depreciation expense associated with production by excluding general and common and intangible plant. I left depreciation expense on peaking plants in the production demand cost category. For each non-peaking plant, I calculated a benchmark amount of deprecation (on a per MW basis) that would have occurred if peaking units of similar size had been built around the time of the baseload units. I benchmarked "old" (*i.e.* greater than 30 years old) units against the oldest of Tri-State's peaking plants (the Burlington plant, which came online in 1977). I benchmarked "newer" units against the average per-kW amount of depreciation expense for Tri-State's newer peaking units that came online in the 2000's. I compared the actual per-kW depreciation expense on each baseload plant against the appropriate benchmark and calculated the total "excess depreciation" based on the size of the plant. This resulted in an allocation of 45% of depreciation expense associated with production plant to energy and 55% to demand.

I allocated the remaining components of depreciation (*i.e.*, deprecation on general and common and intangible plant) between production energy and demand cost components based on the 45:55 split from production plant depreciation expenses. I also allocated regulatory credits/amortization associated with power production plant in the same proportion as production depreciation.

Q: DID YOU SIMILARLY RE-ALLOCATE A PROPORTION OF CAPACITY-RELATED INTEREST COSTS?

A: Yes. While interest costs were not directly part of Dr. Blake's analysis, I needed to examine the proper allocation of interest costs in order to allocate return on rate base correctly in my modifications of Mr. Higgins's analysis. As with my analysis of depreciation expenses, I constructed a benchmark unit interest cost and compared actual unit costs to the benchmark. I allocated excess amounts to energy rather than to demand.

Q: PLEASE EXPLAIN YOUR TREATMENT OF RENT (LEASE) EXPENSES.

A: Dr. Blake attributed all of Tri-State's rent (lease) expenses to production demand. Similar to expenses on Tri-State-owned generation, these lease expenses should be allocated with regard to the difference in capital costs among plant types. If any of Tri-State's lease agreements were for a peaking plant, I would attribute the entire associated lease expense to production demand. However, to take into account the fact that the incremental cost of building more expensive baseload generation is undertaken for the purpose of providing energy at a lower cost, I allocate a portion of the lease expense on baseload and intermediate plants to production energy. I do so according the capital cost ratio for a baseload or an intermediate plant to a peaking plant using representative capital cost values for each type of plant.[37] I determined that 51% of lease expenses are attributable to production demand and 49% are attributable to production energy.

Q: HOW DID YOU USE THE RESULTING OVERALL RE-ALLOCATION OF EXPENSES FROM THIS ANALYSIS?

A: I used the expenses as re-allocated through my analysis of Dr. Blake's cost of service study as the starting point for modifying Mr. Higgins's calculations. Mr. Higgins uses Dr. Blake's analysis of 2012 expenses, increases them by 4.9% to reflect the overall cost of service increase from 2012 to 2013, removes revenues for sales to non-members, adds a margin (5.31% return on rate base), and calculates the demand and energy components of

[37] Provided by Tri-State (peaking, intermediate, baseload).

the total revenue requirement. He finds 56% of the total revenue requirement (in 2013) to be attributable to demand and 44% to be attributable to energy.

Q: WHAT WERE THE ADDITIONAL MODIFICATIONS YOU MADE TO MR. HIGGINS'S ANALYSIS?

A: In addition to replacing the inputs which Mr. Higgins took from Dr. Blake's analysis with my modified analysis described above, my adjustments to account for the margin (return on rate base) and for non-member sales differed from those of Mr. Higgins. I applied the 4.9% increase between 2012 and 2013 in the same way as Mr. Higgins did.

Mr. Higgins applied the 5.31% return on rate base margin to the amount in each rate base category as presented in Dr. Blake's analysis (Exhibit MJB-4(b), rows 338–342). However, just as Dr. Blake allocated 100% of capacity-related depreciation to demand, he allocated 100% of capacity-related rate base to demand. I allocated a portion of capacity-related net rate base to energy, in the same way that I allocated a portion of interest cost. The logic is the same as for the allocations of expense items I described above: if Tri-State had been adding capacity to meet peak demand rather than to optimize the production of cheap baseload energy, it would not have had such a large investment in net production plant, and the amount of rate base allocated to production demand would have been smaller. I reclassified 53% of net rate base they classified as production demand to production energy. I then allocate the $137.1 million margin (5.31% of total rate base) across the rate base categories in proportion to their contribution to total rate base. Finally, I allocated non-member sales to demand and energy in proportion to the total costs allocated to demand and energy, including return on rate base. My final cost of service allocation assigns 63% of expenses to energy and 37% to demand.

V. CONCLUSIONS

Q: PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT DR. BLAKE'S AND MR. HIGGINS'S TESTIMONIES.

A: Dr. Blake and Mr. Higgins argue that rates should provide accurate price signals to encourage the economically efficient use of resources, but their analyses and recommendations are inconsistent with that principle in three ways: (1) they do not consider current incremental costs to serve, which would be necessary for informing efficient prices; (2) in their allocation of Tri-State's costs to demand-related costs and energy-related costs, they do not account for the fact that meeting peak load necessitates building only a peaking resource, and the incremental cost of building more expensive baseload generation is undertaken for the purpose of providing energy at a lower cost; this oversight leads to an overstated price of meeting peak demand; and (3) after calculating demand-related costs, Mr. Higgins proposes a benchmark rate that recovers those costs on a monthly non-coincident peak basis, which bears little relationship to the system coincident peak demand that drives capacity costs in the long term.

Q: AND WHAT ARE YOUR CONCLUSIONS ABOUT TRI-STATE'S CURRENT COSTS OF MEETING PEAK DEMAND?

A: Tri-State's incremental cost of meeting additional peak demand is currently minimal. This is because Tri-State's system has surplus capacity for the next several years relative to its 15% reliability-based planning reserve margin target. Thus, Tri-State is able to reliably satisfy growth in peak demand without investing in new generating capacity. Not until approximately 2019 will the incremental cost of meeting peak demand rise as Tri-State's capacity surplus and the region's surplus come within three years of depletion, and Tri-State may have to decide to build additional capacity. At such time, incremental capacity costs are projected to rise to less than $69/kW-year, which I estimate to be Tri-State's levelized cost of building a peaking generation resource before subtracting the energy value of such a resource. Both the current cost of meeting peak demand and the long-term cost are therefore much less than the year suggested by Complaining Parties' witnesses for "production demand" (*i.e.*, capacity) costs.

Q: WHAT DID YOU FIND ABOUT HOW MUCH OF TRI-STATE'S EMBEDDED COSTS WERE CAUSED BY PEAK DEMAND?

A: I adjusted Dr. Blake and Mr. Higgins's cost of service study by attributing a portion of the fixed costs of baseload generation to accessing low-cost energy rather than meeting peak demand. I find only 34% of Tri-State's 2012 cost is demand-driven, compared to 49% in Dr. Blake's testimony. After making adjustments similar to Mr. Higgins's to account for non-member revenues and other factors, I find 37% of Tri-State's revenue requirement is demand-driven, compared to 56% in Mr. Higgins's version.

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes.