BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	**)))))))))**	**DOCKET NO. 11-035-200**

COMMENTS ON PACIFICORP PROPOSED STRESS FACTOR ANALYSIS

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On Behalf of the

UTAH INDUSTRIAL ENERGY CONSUMERS

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CONTINENTAL ECONOMICS

I. INTRODUCTION AND SUMMARY

On behalf of the Utah Industrial Energy Consumers ("UIEC"), Continental Economics has been asked to prepare comments on the proposed Stress Factor Study Plan ("SFS Plan") described in the attachment to the letter filed by Rocky Mountain Power ("RMP") on July 1, 2013. The proposed SFS Plan is designed to comply with Paragraph 55 of the Stipulation in Docket No. 11-035-200.

The apparent purpose of the SFS Plan and the five different proposed methodologies therein, is to provide a just and reasonable basis for allocating fixed generation asset costs among RMP's customer classes. None of the methodologies proposed does this; they are arbitrary mathematical exercises that have nothing to do with appropriate cost allocation principles and ignore basic economics. As such, none of the proposed methodologies will result in an efficient allocation of fixed generating costs (i.e., one that is consistent with cost-causation principles) and, as a consequence, all will lead to electric rates that are not just and reasonable. As a consequence, these rates will lead to inefficient electric consumption decisions by customers and inefficient utility investment decisions.

From the standpoint of the fundamental principles of cost allocation, none of the five proposed methods are reasonable. We are not aware of any other regulatory jurisdiction – neither state utility regulatory commissions nor the Federal Energy Regulatory Commission – that uses the "stress factor" concept. Nor has the concept ever been presented in the academic or professional literature. Instead, the "stress factor" concept is unique to PacifiCorp.

The SFS analysis has been used to justify the allocation of generation costs among the different states in PacifiCorp's service territory. Currently, Utah uses the interstate allocation methodology to allocate RMP's generating costs among the Company's different rate classes. The ultimate purpose of the proposed SFS Plan is to review and, if appropriate, update the Company's allocation of generation capacity costs to rate classes in Utah.

The stress factor approach is supposedly consistent with measuring system reliability, based on the statistical concept of Loss of Load Probability ("LOLP").[1] However, none of the five proposed methods contained in the SFS Plan actually measures LOLP, nor do any of the methods estimate probabilities in any statistical sense. Instead, the five methods proposed are arbitrary and none is likely to lead to an economically efficient allocation of fixed generation costs.

II. FUNDAMENTALS OF UTILITY COST ALLOCATION

One of the most fundamental goals of utility regulation is to attempt to approximate the results that would take place in a workably competitive retail market, even though the underlying market is not competitive.[2] If costs are not allocated properly, then it is not possible to design rates and tariffs that promote efficient consumption decisions, and are fair. Poorly designed rates, in turn, lead to utilities making economically inefficient investment decisions to meet customer demand. That, in turn, will raise the utilities' overall costs, which must then be paid by retail customers. Additionally, proper cost allocation is a matter of fairness. Allocating costs to groups of customers that are caused by other groups of customers is inequitable. These two principles for evaluating rates and rate structures were set forth over 50 years ago by James Bonbright in his *Principles of Public Utility Rates*.[3]

Allocating variable costs is generally straightforward because such allocations are based on volumetric measures. By definition, variable costs vary with respect to output or sales, and so they are easily associated with the quantities that cause the variations. Allocating fixed costs is quite another story. Because many types of fixed costs are joint or common, in the absence of

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1 LOLP is used interchangeably with "Loss of Load Expectation" ("LOLE").

2 The concept of "workable competition" was developed by the economist John Clark, who developed the concept in recognition that the notion of "first perfect competition" and "perfectly competitive" markets really did not exist. See John M. Clark, "Towards a Theory of Workable Competition," *American Economic Review* 30 (June 1940), pp. 241-256.

3 James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press 1961). Principles six and eight are, respectively, "Fairness in apportionment of total costs of service among different consumers;" and "Efficiency in discouraging wasteful use while promoting justified use." (5th ed., 1969, p. 261.)

competitive markets, numerous methodologies were developed to allocate fixed costs among different customer groups.[4]

In the instant proceeding, the focus is on how to allocate RMP's fixed generating costs, especially the costs associated with meeting peak demand. The five SFS Plan methodologies all focus on peak demand and peak energy use. Thus, the SFS Plan is geared towards assigning what the economist Alfred Kahn deemed *peak-responsibility*.[5] In the short-run, capacity, such as total generating capacity or pipeline capacity, is fixed.[6] As a result, allocating capacity costs among customers based solely on short-run marginal costs will not recover all of a utility's embedded capacity costs. For example, the variable operating costs of a nuclear power plant are quite low compared with the overall costs of the plant, which are primarily fixed costs. If a regulated utility can only charge customers for the short-run variable costs, then it will be unable to recover the nuclear plant's fixed capacity costs. This is why Kahn, as well as Bonbright, focused on long-run marginal costs ("LRMC"), which reflect changing capacity levels and are a "pure economic" approach to allocating capacity costs.

A. <u>Cost Allocation and Market Pricing</u>

The cost allocation methodologies described in the NARUC Manual were developed before competitive wholesale electric markets existed. Thus, regulators were forced to develop

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4 National Association of Regulatory Utility Commissioners (NARUC), *Electric Utility Cost Allocation Manual* (Washington, DC: NARUC, 1992) ("NARUC Manual").

5 Alfred M. Kahn, *The Economics of Regulation*, (Boston, MA: MIT Press 1988) ("Kahn 1988"), pp. 87-103. As he states, "The economic principle here is absolutely clear: if the same type of capacity serves all users, capacity costs as such should be levied only on utilization at the peak. Every purchase at that time makes its proportionate contribution in the long-run to the incurrence of those capacity costs and should therefore have the responsibility reflected in its price. No part of those costs should be levied on off-peak users." *Id*., p. 89 (italics in original). Kahn also addresses changing capacity usage, but again the same principle applies, in which capacity costs are allocated based on relative intensity of demand and price elasticity. *Id*., pp. 91-93. As discussed in Section IV.A, *infra*, this is precisely how capacity costs are allocated in western US wholesale electric markets.

6 One well-known case that was decided by the Federal Power Commission (FPC), the precursor to FERC, addressed how to allocate natural gas pipeline costs. In that case, the FPC allocated pipeline capacity cost equally between demand and commodity charges. This methodology preceded FERC's "modified fixed –variable" (MFV) approach and the current "straight fixed-variable" approach, which allocates 100% of capacity costs to demand charges. *See In the Matters of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation*, Opinion No. 225, 11 FPC 43 (1952).

methodologies that, in theory, would allocate costs in a way that mimicked the outcome of a competitive market. Of course, because no competitive markets existed, there was no way for regulators to test their cost allocation methodologies against market-based cost allocation.

Today, there are vibrant competitive wholesale electric markets. In PacifiCorp's Pacific Northwest service territory, the two main liquid electric trading markets are Mid-Columbia ("Mid-C") and the California—Oregon Border ("COB"). In addition, the Four Corners, Mead (Nevada), and Palo Verde trading hubs also provide wholesale market liquidity and are potential sources of energy supplies for PacifiCorp and its subsidiaries.

Although Utah does not have retail competition, PacifiCorp (and RMP) increasingly rely on wholesale electric markets for supplies. The prices the company pays for wholesale electricity reflect efficient cost allocation and pricing principles. Thus, as summer peak demand continues to increase in the RMP service territory, driven by growth in air conditioning load, RMP must purchase greater amounts of generation in the summer at higher summer prices. The fundamental economic goal of economic regulation – to mimic the outcome of a workably competitive market – should underlie the allocation of fixed generating costs among RMP's customer classes. As discussed in the next section, none of the five proposed stress factor methodologies in the SFS Plan do so.

III. REVIEW OF THE PROPOSED STRESS FACTOR METHODOLOGIES

A fundamental flaw with each of the proposed stress-factor methods is that PacifiCorp never specifically defines what "stress" means. The implicit definition appears to be "the ability of the Company to meet load" at a given time. Although this is superficially consistent with loss of load probability ("LOLP", discussed in section III.A, *infra*), it is far different from an empirical standpoint. And, as discussed below, none of the five methods proposed by PacifiCorp can be considered a LOLP analysis, which underlies all reliability determinations.

The numerical analyses also appear to treat the PacifiCorp system as an "island" within the WECC. Again, from the standpoint of calculating LOLP, that is incorrect. The overriding purpose of the WECC, as well as power pools/ISOs/RTOs, is to provide reliability at a lower cost (e.g., with lower reserve margins) by creating a system of multiple utilities and generating plants. Doing so diversifies outage risk, much as a diversified financial portfolio has less volatility than an undiversified one. Because PacifiCorp operates within the WECC, LOLP measures will properly account for the company's interconnection to the WECC grid. Capacity can be provided by the market from generating resources throughout the WECC. Demand response (DR) resources can also provide capacity reserves, as they do in several RTOs, such as PJM.

The review of the five proposed stress-factor methods is based on two fundamental criteria:

1. <u>Consistency with a true LOLP measure</u>. Does the proposed method provide an equivalent proxy estimate for LOLP? Does the method provide statistical probability values?

2. <u>Consistency with principles of economic efficiency</u>. Is the proposed measure consistent with how costs are allocated in the competitive wholesale market?

A. <u>LOLP Defined</u>

LOLP is a statistical concept. It is measured using complex hourly power flow models. These models simulate the power system's ability to maintain power flow during contingent events, such as forced generator outages and loss of transmission lines, which take place randomly. Load in each hour is also uncertain, influenced by both seasonal trends and uncertain weather. The models are run multiple times (called a Monte-Carlo analysis). For a given amount of generation capacity reserve, each iteration (or "draw") adjusts load randomly up or down from an expected level, as well as randomly determines whether a contingent event takes place. The standard planning criteria, a 1-in-10 year LOLP, means an expectation of 2.4 hours of lost load each year, or 24 hours once every 10 years. The planning reserve margin is calculated such that it is consistent with the 1-in-10 year LOLP.

It is important to note that the relationship between reserve margin and LOLP is <u>non-linear</u>. That is, there is no one-to-one simple correspondence between changes in reserve margin (measured as a percentage of system peak demand) and LOLP. Intuitively, as the reserve margin decreases to zero percent (i.e., system resources equal expected peak load), the probability that a contingent event will result in loss of load increases to a probability of 1.0 (i.e., certainty).

B. Method 1: Highest hourly monthly demand for power used by firm load customers

Consistent with a true LOLP measure?	**NO**
Consistent with economic efficiency?	**YES***

* if interpreted correctly

Method 1 uses monthly firm peak demand as a proxy for system "stress." Method 1 is consistent with a traditional coincident peak ("CP") determination, in that it determines the month(s) in which peak demand is highest. Under a traditional CP cost allocation, fixed generation costs are allocated based on each the relative contribution to the system CP during the highest demand month. Thus, Method 1, if the results are interpreted correctly, is consistent with principles of economic efficiency.

In its 2013 Integrated Resource Plan ("2013 IRP"), PacifiCorp stated that, for purposes of evaluating the reliability of its resource supply, it evaluates energy not served ("ENS") as part of an evaluation of LOLP. Specifically, the 2013 IRP states:

> Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time.
>
> For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels.f ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, <u>only events that occur at the time of the regional peak are the ones likely to have significant consequences</u>. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Appendix L in Volume II of this report, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring in the winter season.[7]

[7] 2013 IRP, p. 198.

Thus, based on its own IRP, Pacificorp's focus on reliability is the summer period. Yet, as the Company notes in its discussion of Method 4, there is a possibility of lower reserve margins in off-peak months because of planned maintenance outages. Does this mean there is more "stress" on the PacifiCorp system in off-peak months? Not from the standpoint of the wholesale market, in which prices typically reach their maximum during the summer months and are lowest in off-peak months. The entire purpose of scheduling maintenance outages during the off-peak months is because regional demand is low.

As PacifiCorp notes in the "con," Method 1 "does not evaluate the ability of the Company to meet load in the peak hour." That is clearly true, because the method, like all of the other proposed methods, is completely different than the LOLP analysis described in the PacifiCorp IRP.

C. <u>Method 2: Probability of Contribution to Peak (1)</u>

Consistent with a true LOLP measure?	**NO**
Consistent with economic efficiency?	**NO**

First, we note that the definition refers to "annual peak load," whereas the "intended to show" refers to "average load." By definition, there can be no hours during which load exceeds the annual peak load.

For our purposes, we assume PacifiCorp is reproducing the 2003 Stress Factor Analysis, which identified the number of hours in each month during which actual hourly loads (for the years 2001 and 2002) and forecast hourly loads (for the years 2004 – 2008) exceeded 83% of the annual peak load.

PacifiCorp previously used the 83% value because the available energy of all of its resources supposedly was 83% of the peak capability. For example, if the annual peak capability were 1,000 MW, then, if the load in a given hour were greater than 830 MW, that hour would be considered as one "contributing" to peak load. So, to use another hypothetical, if loads exceeded 830 MW a total of 100 hours during a given month, then the "probability of contributing to system peak" in that month would be 100 hours / 720 hours = 0.139. In other words, this "stress factor" analysis would conclude there is a 14% "probability" that June will contribute to the peak.

Method 2 revises this 2003 stress factor analysis simply by changing the 83% value to a range of estimates between 70% and 99% of annual peak load. PacifiCorp recognizes two problems with this approach: (1) the methodology does not measure the magnitude by which load exceeds the annual peak;[8] and (2) the potential for overlap with a system generation allocator that is based, in part, on energy use. In addition, the method does not provide a valid LOLP measure. To do that, load must be combined with system operation to analyze LOLP. This method assumes a non-existent linear relationship between hours where load exceeds annual average system load and LOLP.

Moreover, PacifiCorp does not address how the probability of contribution to peak load determines cost allocation. For example, suppose the analysis shows that there is a positive probability of contribution to peak load in all months. Does this mean that fixed generation costs should be based on an average of monthly coincident peaks of each customer class? The link between the probability of contributing to peak and economic efficiency is non-existent.

D. <u>Method 3: Probability of Contribution to Peak (2)</u>

Consistent with a true LOLP measure?	**NO**
Consistent with economic efficiency?	**NO**

Method 3 purports to be a similar LOLP-type of approach, except one that is based on energy consumption, not load. As a consequence, it is even more flawed than Method 2. Based on this method, a constant but lower load that occurs over many hours in a month can be "more stressful" to the system than a short duration but far higher load because the former represents more total energy consumption. For purposes of allocating fixed costs, this makes no economic

[8] PacifiCorp refers to both "annual peak" and "annual average" firm load.

sense because it does not reflect cost causation. For example, suppose a peaking unit must be operated for ten hours during July when residential air conditioning load peaks. Suppose also there is a 7x24 industrial process load that is greatest in the month of November and that this load means more total MWh in November exceed average load than in July. Under this method, the constant industrial process load places more “stress” on the PacifiCorp system than does the residential air conditioning load driving the need to run the peaking unit.

The method also suffers from same economic efficiency problems as the first probability of contribution to peak method, in that there is no specific relationship between such “probabilities,” cost allocation, and economic efficiency.

E. Method 4: Monthly Reserve Margins

Consistent with a true LOLP measure?	**NO**
Consistent with economic efficiency?	**NO**

The Company’s operating reserve margin is based on WECC criteria and considers PacifiCorp as part of the entire WECC system.[9] Instead, Method 4 wrongly assumes PacifiCorp is an island. As the Company itself points out, reserve margins may be lower in low-demand months because these are the rational months for planned outages of generators. No utility schedules outages for the highest-demand months. Moreover, as we discussed previously, this method assumes there is a linear relationship between reserve margin and LOLP, which is not true.

Moreover, as we discussed in section III.A, this method reverses causality. In other words, for reliability planning purposes, reserve margins are determined based on LOLP analysis, which takes into account uncertain load. Thus, measured on a load basis, system “stress” determines required reserve margins. Instead, Method 4 appears to reverse this causality.

[9] PacifiCorp’s planning reserves are based on LOLP analysis.

F. <u>Method 5: Cost of Peak Resources</u>

Consistent with a true LOLP measure?	**NO**
Consistent with economic efficiency?	**NO**

Method 5 relies on flawed economics and is an "apples to oranges" comparison of PacifiCorp resources to the wholesale market. Specifically, Method 5 compares the *marginal* cost of wholesale market resources to the *embedded* costs of PacifiCorp's gas-fired peaking units. This has no relationship whatsoever with LOLP.

Furthermore, this comparison has no relationship to economic efficiency, because it does not address how PacifiCorp operates its resources. Under economic dispatch, PacifiCorp dispatches its generating resources in order of their increasing *marginal* operating costs, not their *embedded* costs. In the presence of the wholesale market, economic dispatch should also include the marginal cost (i.e., the market price) of wholesale power. Thus, it is economically efficient for PacifiCorp to purchase electricity from the market whenever that power costs less than the marginal cost of operating its own generating units.[10] Purchase decisions in the wholesale market have nothing to do with embedded generation costs. In other words, PacifiCorp does not compare the market price of energy in the wholesale market with the embedded costs of its generating units.

As a result of this fundamental mismatch, Method 5 has no economic basis. If a company relies on the wholesale market, as PacifiCorp increasingly does, to meet its energy and capacity needs, and doing so is less costly than building new generating resources, then the wholesale market is obviously providing system reliability and reducing "stress."

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[10] This is a general statement. We recognize that some baseload units must run even when market prices are below their marginal operating costs because of the inherent costs of cycling plants, and so forth.

IV. THE WHOLESALE COMPETITIVE MARKET PROVIDES THE INFORMATION NEEDED TO ALLOCATE FIXED COSTS

As discussed previously, there is a vibrant competitive wholesale electric market in WECC. Market prices inherently reflect system "stress," because market prices automatically reflect supply and demand conditions. For example, Palo Verde forward prices are highest in summer, reflecting the increase in electric demand driven by air conditioning load.

Market prices in workably competitive wholesale markets reflect demand patterns and efficiently by accounting for the interactions of supply and demand. In short, using wholesale market pricing patterns to allocate fixed costs is the "pure economic" approach referenced by Kahn. It makes no sense – economic or regulatory – to ignore the information these markets provide for allocating costs among customer classes. As discussed previously, of the five proposed methods, only Method 1 provides any possible semblance of economic efficiency.

A. <u>Illustrative Example: Using Market Prices to Allocate Fixed Generation Costs</u>

It is important to remember that cost allocation methodologies, such as those presented in the NARUC Cost Allocation Manual, were all developed before there were competitive wholesale generation markets. In states with full retail competition, fixed generation cost allocation is not an issue, because those allocations are all determined in the marketplace.

Even if customers in Utah do not have direct retail access, we can still use the information provided by WECC's wholesale electric markets as a guide towards allocating fixed costs. This section provides an illustrative description of how wholesale market prices could be used to accomplish this.

To begin with, suppose all RMP customers purchase their electricity in the wholesale market at the hourly real-time spot market price. Suppose further that each individual customer's consumption is similarly tracked on an hourly basis. Then, for each customer *k* in class *j*, the annual cost for purchased electricity, $c_{i,j}$, is just the sum of all of the hourly expenditures, i.e.

$$c_{k,j} = \sum_{t=1}^{8760} q_{k,j,t} \bullet p_i \tag{1}$$

where: $q_{i,j,t}$ = consumption by customer i in class j during hour t, and p_t = the market price in hour t. Next, consider the total cost of electricity purchased during the year in each separate customer in class j, C_j. The total purchase cost for all customers in class j is:

$$C_j = \sum_{i=1}^{K} c_{k,j} \tag{2}$$

where: K = the total number of customers in class j. Finally, the total cost of electricity purchases for all customers in all customer classes, C, is just the sum of the total costs in each individual customer class, or

$$C = \sum_{i=1}^{J} C_j \tag{3}$$

where: J = the total number of customer classes.

We know that workably competitive market prices reflect supply and demand conditions. In hours where demand peaks, such as the summer, market prices are higher, reflecting the higher marginal cost to supply additional electricity. These prices send signals to suppliers regarding the economic benefits of additional investment in generating capacity. In this scenario, fixed costs are allocated efficiently by definition. Consumers who use the most electricity in peak hours pay relatively more towards recovery of fixed generation costs than do consumers who use less electricity. For example, in hours where there is surplus hydroelectric or wind generation, such as the spring, market prices may fall to zero, or even be negative. In those hours, customers who purchase electricity are clearly not contributing to fixed cost recovery whatsoever. As a result of market pricing, customers in each class pay an efficient share of total electric costs, based on the prices in a workably competitive market, and there is no need to use any "traditional" cost allocation methodology to allocate fixed generation costs. Nor is there an issue of whether some customers subsidize consumption by other customers.

PacifiCorp (and RMP) increasingly rely on wholesale electric markets for supplies. The prices the company pays for wholesale electricity reflect efficient cost allocation and pricing principles. For example, because summer peak demand continues to increase in the RMP service territory, driven by growth in air conditioning load, RMP must either purchase greater amounts of generation in the summer, at higher summer prices or invest in new generation facilities to meet the higher summer peak loads.

Because WECC does not have a separate capacity market, the market price in each hour reflects the sum of both variable (energy) and fixed (capacity) costs. Allocating variable costs is straightforward: those costs are allocated strictly based on consumption. Therefore, if we can separate out the variable costs in each hour from the total market price, we can determine the total fixed costs for the year.

The genesis of the illustrative approach consists of three steps:

Step 1. Determine the total market-based cost of energy for each customer class during the year, based on historic loads and prices, as discussed above.

Step 2. Subtract RMP's marginal variable energy cost from each customer class in each hour from the market price in each hour. (RMP's marginal cost should be equal to or less than the market price; if it is less costly for RMP to purchase generation in the market than run its own generation, then it makes economic sense for the company to purchase power in the market.) The difference between the market price and RMP's marginal cost, $p_t - MC_t$, can then be thought of as a proxy for the portion of RMP's fixed generation costs that would be recovered if RMP sold all of its generation into the market in that hour.

Step 3. Aggregate these fixed costs over the entire year for each customer class to determine the percentage of net "fixed" costs by customer class, and allocate RMP's fixed generation costs using those percentages.

B. An Illustrative Example

Consider an example where there are three customer classes, A, B, and C. Class A has one customer with a constant year-round load of 525 MW in all hours. Customer Class B has 100 customers, each having summer peaking load. Customer C has customers whose load peaks in the spring and fall periods, but is zero during the summer peak months of July and August. To make the example easier, rather than using 8,760 separate hours for the analysis, assume that load for each customer class remains constant within each month. Thus, we can calculate total electric consumption by each customer class in each month, as shown in Table 1.

Table 1: Illustrative Example

Month	Hrs in Month	Load (MW) A	B	C	Total	Total Energy (MWh) A	B	C	Total
January	744	525	650	400	1,575	390,600	483,600	297,600	1,171,800
February	672	525	575	450	1,550	352,800	386,400	302,400	1,041,600
March	744	525	450	500	1,475	390,600	334,800	372,000	1,097,400
April	720	525	400	600	1,525	378,000	288,000	432,000	1,098,000
May	744	525	675	300	1,500	390,600	502,200	223,200	1,116,000
June	720	525	1,100	100	1,725	378,000	792,000	72,000	1,242,000
July	744	525	1,650	0	2,175	390,600	1,227,600	0	1,618,200
August	744	525	1,600	0	2,125	390,600	1,190,400	0	1,581,000
September	720	525	1,200	200	1,925	378,000	864,000	144,000	1,386,000
October	744	525	600	500	1,625	390,600	446,400	372,000	1,209,000
November	720	525	625	600	1,750	378,000	450,000	432,000	1,260,000
December	744	525	595	400	1,520	390,600	442,680	297,600	1,130,880
	Total Energy					4,599,000	7,408,080	2,944,800	14,951,880
	Total Cost					$ 309,834,000	$620,754,000	$143,628,000	$1,074,216,000
	Pct of Total					29%	58%	13%	100%

Similarly, to make the example easier, assume that the market price is constant in each hour during each individual month. Table 2 shows these market prices, as well as RMP's assumed marginal cost of generation in each month. RMP's marginal cost of generation is also assumed constant within each hour of each month.

Table 2: Market Price and RMP Marginal Cost of Generation

Month	Mkt. Price ($/MWh)	RMP MC ($/MWh)
January	$55	$40.00
February	$50	$40.00
March	$45	$40.00
April	$40	$40.00
May	$50	$40.00
June	$65	$40.00
July	$150	$75.00
August	$140	$75.00
September	$65	$40.00
October	$50	$40.00
November	$45	$40.00
December	$50	$40.00

Applying equations (1) and (2), we can calculate the total expenditures on electricity in each month. This is shown in Table 3.

Table 3: Total Expenditures

Month	Class A	Class B	Class C	Total
January	$21,483,000	$26,598,000	$16,368,000	$64,449,000
February	$17,640,000	$19,320,000	$15,120,000	$52,080,000
March	$17,577,000	$15,066,000	$16,740,000	$49,383,000
April	$15,120,000	$11,520,000	$17,280,000	$43,920,000
May	$19,530,000	$25,110,000	$11,160,000	$55,800,000
June	$24,570,000	$51,480,000	$4,680,000	$80,730,000
July	$58,590,000	$184,140,000	$0	$242,730,000
August	$54,684,000	$166,656,000	$0	$221,340,000
September	$24,570,000	$56,160,000	$9,360,000	$90,090,000
October	$19,530,000	$22,320,000	$18,600,000	$60,450,000
November	$17,010,000	$20,250,000	$19,440,000	$56,700,000
December	$19,530,000	$22,134,000	$14,880,000	$56,544,000
Total	**$309,834,000**	**$620,754,000**	**$143,628,000**	**$1,074,216,000**

Next, following the three-step methodology, we subtract out the variable energy costs incurred by RMP to determine the fixed cost contribution by each customer class in each month. The remaining fixed costs in each month are shown in Table 4.

Table 4: Fixed Cost Contribution in Each Month

Month	Class A	Class B	Class C	Total
January	$5,859,000	$7,254,000	$4,464,000	$17,577,000
February	$3,528,000	$3,864,000	$3,024,000	$10,416,000
March	$1,953,000	$1,674,000	$1,860,000	$5,487,000
April	$0	$0	$0	$0
May	$3,906,000	$5,022,000	$2,232,000	$11,160,000
June	$9,450,000	$19,800,000	$1,800,000	$31,050,000
July	$29,295,000	$92,070,000	$0	$121,365,000
August	$25,389,000	$77,376,000	$0	$102,765,000
September	$9,450,000	$21,600,000	$3,600,000	$34,650,000
October	$3,906,000	$4,464,000	$3,720,000	$12,090,000
November	$1,890,000	$2,250,000	$2,160,000	$6,300,000
December	$3,906,000	$4,426,800	$2,976,000	$11,308,800
Total	**$98,532,000**	**$239,800,800**	**$25,836,000**	**$364,168,800**
Fixed Cost Pct:	**27.1%**	**65.8%**	**7.1%**	**100.0%**

As Table 4 shows, there is a contribution to fixed cost in every month except April. Under the methodology, Class A would be allocated 27.1% of fixed generation costs for the year, Class B would be allocated 65.8%%, and Class C would be allocated 7.1%. We can compare these fixed cost allocation percentages with those under a traditional coincident peak methodology.

Table 5: Fixed Cost Allocation Percentages – Traditional CP Method

Methodology	Class A	Class B	Class C	Total
1-CP	24.1%	75.9%	0.0%	100.0%
3-CP	26.1%	72.2%	1.7%	100.0%
4-CP	26.4%	69.8%	3.8%	100.0%
12-CP	30.8%	49.4%	19.8%	100.0%
Market-Based	**27.1%**	**65.8%**	**7.1%**	100.0%

As Table 5 shows, in this example, a 12-CP approach would allocate more than twice the fixed costs to Class C customers than would the market, while allocating far less to Class B customers than the market.

The importance of this illustrative example is to show how market data can inform fixed cost allocation, even if customers do not have direct retail access. The advantage of such a market-based approach is (1) it leads to an economically efficient allocation of costs; and (2) avoids the controversy over the reasonableness of choosing among different non-market-based allocators, all of which are arbitrary. In effect, the wholesale market information is available. There is no reason not to use it to help determine fixed generation cost allocation.