Gary A. Dodge, #0897
HATCH, JAMES & DODGE
10 West Broadway, Suite 400
Salt Lake City, UT 84101
Telephone: 801-363-6363
Facsimile: 801-363-6666
Email: gdodge@hjdlaw.com
Attorneys for UAE

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule 32, Service from Renewable Energy Facilities	**Docket No. 14-035-T02**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

The UAE Intervention Group (UAE) hereby submits the Prefiled Direct Testimony of Kevin C. Higgins.

DATED this 9th day of September, 2014.

/s/______________________________
Gary A. Dodge,
Attorney for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 9th day of September 2014 on the following:

Rocky Mountain Power:	
Jeff Richards	jeff.richards@pacificorp.com
Yvonne Hogle	yvonne.hogle@pacificorp.com.com
Dave Taylor	dave.taylor@pacificorp.com
Division of Public Utilities:	
Patricia Schmid	pschmid@utah.gov
Justin Jetter	jjetter@utah.gov
Chris Parker	chrisparker@utah.gov
Artie Powell	wpowell@utah.gov
Dennis Miller	dmiller@utah.gov
Abdinasir Abdulle	aabdulle@utah.gov
Office of Consumer Services:	
Brent Coleman	brentcoleman@utah.gov
Michele Beck	mbeck@utah.gov
Cheryl Murray	cmurray@utah.gov
Ormat Technologies:	
Angie Dykema	adykema@ormat.com
Energy of Utah:	
Ros Vrba	rosvrba@energyofutah.com
Interwest Energy Alliance:	
Lisa Tormoen Hickey	lisahickey@coloradolawyers.net
Sarah Cottrell Propst	propst@interwest.org
Wal-Mart/Sam's Club:	
Meshach Y. Rhoades	rhoadesm@gtlaw.com
Steve W. Chriss	Stephen.Chriss@wal-mart.com
Utah Clean Energy:	
Sophie Hayes	sophie@utahcleanenergy.org
Sarah Wright	sarah@utahcleanenergy.org
Ebay:	
Brian W. Burnett	brianburnett@cnmlaw.com

/s/ ______________________________

BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 14-035-T02

September 9, 2014

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Utah Association of Energy Users Intervention Group ("UAE").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. Since 1984, I have testified in thirty-three dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 150 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission ("FERC") and prepared expert reports in state and federal court proceedings involving utility matters.

Q. What is the purpose of your testimony in this case?

A. My testimony addresses the proposal by Rocky Mountain Power ("RMP") for a new Rate Schedule 32, which would provide service to customers utilizing power generated by a renewable energy facility that is either owned by the customer or is under a contractual arrangement with RMP and the customer. Schedule 32 is being introduced to implement Senate Bill 12, which was passed into law in 2012. [Utah Code Title 54, Chapter 17, Part 8.] This statute enables qualifying retail customers to have renewable energy delivered to their premises.

Q. What are the primary conclusions and recommendations in your testimony?

A. I offer the following conclusions and recommendations:

- RMP has divided the proposed Schedule 32 into three interrelated services: delivering the contracted-for renewable energy; "filling in" (or shaping) the power required by the customer when the peak amount of contracted-for renewable energy is not fully available; and providing supplemental power service beyond the contracted-for amount of renewable energy. This division of the rate schedule into these three services is a useful construct.
- I agree with the Company's proposed treatment of supplementary power and energy and have no recommended changes to the Company's proposal for that service.
- The Company's proposed combination of customer charges and administrative fees strikes me as too costly and would likely result in an undue barrier to participation. If Schedule 31 customer charges are used to set the Schedule 32

customer charges, as proposed by RMP, then no additional administrative fee should be imposed. Alternatively, if an administrative fee is imposed, then the fee should be reduced to $200 per month to reflect a more efficient billing process than that assumed by the Company and the customer charges should be set at the charge in the customer's otherwise applicable rate schedule rather than Schedule 31.

- I am not persuaded that the generation backup facilities charge proposed by RMP is appropriate for Schedule 32 service. There is no requirement or mention of a generation backup facilities charge in Senate Bill 12. Instead of adopting this charge, the backup power (or shaping) charge should be designed to recover the customer's pro-rata share of the generation demand costs in proportion to the customer's use of the shaping service, as I explain in detail in my testimony.
- The delivery facilities charges proposed by the Company are too high in relation to the tariff rates currently in effect. Adoption of RMP's proposed rates would cause Schedule 32 customers to be charged more for delivery service than their counterparts on Schedule 9 and Schedule 8 would pay for delivery of RMP power. Instead, these charges should be recalculated as described in my testimony to produce rates that more accurately reflect the delivery-related demand charges actually embedded in Schedule 9 and Schedule 8 rates.
- Although the daily demand charge proposed by RMP for backup power charges is a useful construct, it is, unfortunately, inadequate for reasonably implementing Senate Bill 12 because it is not granular enough. Under the rate design proposed

by RMP for backup (or shaping) power, many Schedule 32 customers would be doomed to receive very little credit, if any, for avoiding RMP's generation demand charges, even when the renewable resource the customer is importing provides reliable capacity during much of the on-peak period. This result is largely an artifact of the definition of the on-peak period and the definition of daily billing demand. A more reasonable approach is to make the daily demand charge more granular by converting it into an hourly demand charge (which I call the "hourly on-peak shaping charge.") By doing so, the Schedule 32 customer would receive a pro rata credit for the renewable energy capacity the customer imports during the on-peak period.

SCHEDULE 32

Q. What objectives should the Commission strive to attain in approving a rate schedule to implement Senate Bill 12?

A. Senate Bill 12 gives Utah customers the ability to do something they cannot do today: acquire off-site renewable energy for delivery to their premises. In implementing this new statute, the Commission should strive to adopt changes to the RMP tariff that will enable customers to successfully make these acquisitions within the constraints prescribed by the legislation. These constraints include a minimum 2.0 MW size threshold for participation and an overall cap of 300 MW on the total program size. The statute also requires that participating customers pay the incremental administrative, metering, and communication costs of participation as well as the cost of delivering the acquired renewable energy across the utility's transmission and distribution system.

At the same time that the Commission assigns participating customers their appropriate share of costs, the Commission should also be careful to ensure that the rate structure it adopts does not result in undue barriers to acquiring and delivering renewable energy to participating customers as intended by the legislature.

To ensure that participating customers are properly credited against their utility bills for the acquired renewable energy, the statute provides that the following items are to be excluded from the customers' utility charges:

(a) any kilowatt hours of electricity delivered from the renewable energy facility, based on the time of delivery, adjusted for transmission losses;
(b) any kilowatts of electricity delivered from the renewable energy facility that coincide with the contract customer's monthly metered kilowatt demand measurement, adjusted for transmission losses;
(c) any transmission and distribution service that the contract customer pays for under Subsection (1) or (2); and
(d) any transmission service that the contract customer provides under Subsection (2) to deliver generation from the renewable energy facility.

In determining whether the proposed tariff changes to implement Senate Bill 12 are reasonable, the Commission should take into account how well the proposal adheres to these required cost exclusions.

Q. What has RMP recommended for implementation of Senate Bill 12?

A. RMP has proposed a new Rate Schedule 32 to implement Senate Bill 12, which is described in the direct testimony of RMP witness David L. Taylor. Schedule 32 is a fairly complex rate schedule that provides for three interrelated services: delivering the contracted-for renewable energy; “filling in” (or shaping) the power required by the customer when the peak amount of contracted-for renewable energy is not fully available; and providing supplemental power service beyond the contracted-for amount of renewable energy.

Q. Under what terms does RMP propose to provide delivery of the renewable energy?

A. This portion of the service has a delivery facilities (or wheeling) charge that is differentiated by voltage. The delivery facilities charge is a monthly demand charge applied to the contracted amount (i.e., maximum hourly delivery) of renewable energy. The delivery facilities charge, along with each of the charges in Schedule 32, has a Step 1 and a Step 2 rate corresponding to the Step 1 and Step 2 rate increases approved in RMP’s recent general rate case. As shown in Table 1 on page 13 of Mr. Taylor’s direct testimony, RMP’s proposed Step 1 delivery facilities charge is $4.29 per kW-month for transmission voltage, $6.83 per kW-month for primary voltage, and $7.97 per kW-month for secondary voltage.

As proposed by RMP, the delivery of renewable energy service also includes a mandatory generation backup facilities charge, which is a demand charge applied to the contracted amount of renewable energy. The Company’s proposed Step 1 rate for this charge is $1.38 per kW-month for transmission voltage and $1.25 per kW-month for primary and secondary voltage.

In addition to these charges, RMP proposes that participating customers pay a customer charge equal to the Schedule 31 customer charge for the corresponding voltage plus an administrative fee of $450 per month.

Q. Why did you classify the generation backup facilities charge as part of the renewable energy delivery service and not as part of the shaping service?

A. As proposed by RMP, the generation backup facilities charge is an unavoidable charge to the customer that is tied to the renewable energy contract demand. Under the Company's proposal, the customer would pay this charge irrespective of whether the customer utilized the shaping service. Consequently, I believe it is most appropriately considered to be part of the Company's proposal for renewable energy delivery service.

Q. Under what terms does RMP propose to provide "shaping" power required by the customer when the peak amount of contracted-for renewable energy is not fully available?

A. There are two cost components to this service: a backup energy charge and a backup power charge. The backup energy charge is for the kilowatt-hours used by the customer when the peak amount of contracted-for renewable energy is not fully available. This charge is the same as the energy charge in the customer's otherwise applicable rate schedule.

The backup power charge is a daily demand charge that is intended to recover generation demand costs associated with the power used by the customer when the peak amount of contracted-for renewable energy is not fully available.

The amount of daily demand billed to the customer is based on the customer's maximum hourly demand in excess of its renewable energy import during any on-peak hour (up to the amount of its renewable energy contract demand). So for example, if a customer has a renewable energy contract demand of 5 MW, and the customer consumes 5 MW each hour of the on-peak period, and its renewable energy output falls to a minimum level of 2 MW during one of the on-peak hours, then the customer's backup power demand for the day would be 3 MW (5 MW minus 2 MW).

Q. Why do you characterize this service as "shaping" service rather than as "backup" service?

A. In general, backup service is needed on those occasions when a resource experiences an outage. In contrast, the shaping product will be needed on a daily basis for most renewable energy resources, even when they are operating entirely as planned. Simply put, in Utah, the wind doesn't blow at a consistent speed every hour of every day and the sun certainly does not shine at 9:00 in the evening very often. So while the shaping service would serve the customer during an outage of its resource, its more fundamental purpose is to provide shaping power every single day.

Q. Under what terms does RMP propose to provide supplementary power and energy in excess of the customer's renewable energy contract demand?

A. RMP proposes to provide this service under the same terms as the customer's applicable rate schedule.

Q. What is your assessment of RMP's Schedule 32 proposal?

A. The Company's division of the rate schedule into the three services I described above is a useful construct. In addition, I agree with the Company's proposed treatment of supplementary power and energy and have no recommended changes to the Company's proposal for that service.

However, I believe a number of changes should be made to other parts of the Company's proposal. I will address each in turn.

Customer Charge and Administrative Fee

Q. What is your concern regarding the proposed customer charge and administrative fee?

A. RMP's proposed monthly customer charges are based on RMP's Schedule 31 rates and are significantly greater than the Schedule 8 and Schedule 9 customer charges for comparable voltages. In *addition* to these substantially higher customer charges, RMP is proposing an administrative fee of $450 per month.

The Company's proposed combination of customer charges and administrative fees strikes me as too costly and would likely result in an undue barrier to participation, particularly for smaller customers that are aggregating load to reach the 2.0 MW minimum size for participation. While the Company justifies the $450 administrative expense based on an estimate of the time required to hand bill each customer – 6 hours per month – I believe it is more likely that some spreadsheet automation would be introduced into the process to bring costs down. Frankly, 6 hours per month, *every* month, simply to bill each participating customer appears unreasonable and inefficient on its face.

Moreover, the Schedule 31 customer charges that RMP is proposing to adopt are already much higher than standard customer charges. For secondary service, the Schedule 31 customer charge of $131 per month is about double the Schedule 8 customer charge and for primary service the Schedule 31 customer charge of $596 per month it is over eight times greater. For transmission voltage service, the Schedule 31 customer charge of $668 per month is more than two and a half times greater than the Schedule 9 customer charge. Given the dramatically greater starting level for the customer charges, I question why *any* additional administrative fee is warranted.

Q. What is your recommendation regarding the customer charge and administrative fee?

A. If Schedule 31 customer charges are used to set the Schedule 32 customer charges, then no additional administrative fee should be imposed. Alternatively, if an administrative fee is imposed, then the fee should be reduced to $200 per month to reflect a more efficient billing process than that assumed by the Company and the customer charges should be set at the charge in the customer's otherwise applicable rate schedule rather than Schedule 31. Of these two options, I believe the second is preferable because it is more directly comparable to customers' otherwise applicable rate schedules.

Generation Backup Facilities Charge

Q. What is your concern regarding the proposed generation backup facilities charge?

A. I am not persuaded that this charge is appropriate for Schedule 32 service. First, Schedule 32 customers will be compensating RMP for "shaping" generation through their monthly payments of backup energy and backup power charges. These charges can be designed to be compensatory to the Company for the service being provided. Second, there is no requirement or mention of a generation backup facilities charge in Senate Bill 12. It is my understanding that RMP was very involved in the discussions that led up to this legislation and would have had ample opportunity to make the case for such a charge as part of that process. As it is, the legislature did not see fit to prescribe this charge, but did provide a 300 MW cap on overall participation, which limits the generation reserves that might be needed to support the customer load in this program. In light of the structure of the legislation, it is reasonable *not* to adopt this charge. Instead, the backup power charge should be designed to recover the customer's pro-rata share of the generation demand costs in proportion to the customer's use of the shaping service, as I will discuss further below.

Delivery Facilities Charges

Q. What is your concern regarding the proposed delivery facilities charges?

A. The charges proposed by the Company are too high in relation to the tariff rates currently in effect.

Q. How did RMP calculate the proposed delivery facilities charges?

A. The Company derived the proposed charges from its cost-of-service study in the last general rate case. To calculate the delivery facilities charge at transmission voltage, RMP identified the transmission costs classified to demand for Schedule 9 and related rate schedules. RMP then reduced this cost by 2.1 percent to adjust for the reduction to the Company's requested revenue requirement that was ultimately approved in the general rate case. This figure was then divided by the Schedule 9 Facilities kW billing determinant to produce a Step 1 rate of $4.29 per kW-month.

RMP followed a similar procedure in determining its proposed primary and secondary voltage delivery facilities charges except that the analysis was performed for transmission and distribution costs classified to demand for Schedule 8.

Q. Why do you believe this approach yields delivery facilities charges that are too high?

A. Although the charges were derived from the Company's cost-of-service study, the actual rates in the Company's tariff do not match the Company's cost-of-service study numbers in the first instance. Consequently, the delivery facility charges proposed by RMP do not reasonably reflect the equivalent "delivery facilities" unit charges actually found in the Schedule 9 or Schedule 8 rate schedules. This mismatch means that Schedule 32 customers would be paying different effective rates for delivery service than their counterparts taking fully bundled service under Schedule 9 or Schedule 8.

To derive a more representative delivery facilities charge for Schedule 9, I used the same cost-of-service study as the Company and calculated the share of transmission demand costs allocated to Schedule 9 (and related rate schedules) as a percentage of total transmission demand and generation demand costs allocated to Schedule 9 (and related rate schedules). I then applied this percentage (28.87%) to the total Step 1 demand revenue requirements approved for Schedule 9 in the recent general rate case and divided through by the Facilities kW billing determinant to yield a Step 1 delivery facilities charge of $3.79 per kW-month. This charge more accurately reflects the transmission demand charge actually embedded in Schedule 9 Step 1 rates. This calculation is presented in UAE Exhibit 1.1, page 1.

I performed a similar calculation for Schedule 8 and derived a primary voltage delivery facilities charge of $6.70 per kW-month and a secondary delivery facilities charge of $7.82 per kW-month. These calculations are presented in UAE Exhibit 1.1, page 2.

Q. What are the consequences if the delivery facilities charges are set too high?

A. The most obvious consequence is that Schedule 32 customers would be charged more for delivery service than their counterparts on Schedule 9 and Schedule 8 would pay for delivery of RMP power. This result would be inequitable and unreasonable. An additional significant consequence is that the RMP generation demand avoided by the Schedule 32 customer would be undervalued. That is, taken together, the delivery (transmission and distribution) and generation functions make up the entirety of a Schedule 9 or Schedule 8 customer’s demand charges. If the Schedule 32 delivery facilities charge is set higher than the effective rate embedded in Schedule 9 (or Schedule 8), then the portion of the Schedule 9 (or Schedule 8) demand charge that the Schedule 32 customer is able to avoid – the generation portion – would be valued at *less* than the generation demand charges embedded in Schedule 9 (and Schedule 8) rates. Not only is such an outcome unreasonable, undervaluing avoided generation demand appears to undermine the statutory requirement that “any kilowatts of electricity delivered from the renewable energy facility that coincide with the contract customer's monthly metered kilowatt demand measurement” must be excluded from the customer’s utility bill.

Backup Power Charges

Q. What is your assessment of RMP’s proposed backup power charges?

A. The structure of the backup power charges proposed by RMP is a useful construct. As I discussed above, the product being provided by the backup power charges is more accurately characterized as “shaping power” rather than “backup power.” The backup power charges designed by the Company are daily demand charges, rather than monthly demand charges. The daily demand charge is a useful construct because it attempts to charge the Schedule 32 customer for the customer’s daily utilization of generation demand in excess of the generation demand the customer is already paying for in the generation backup facilities charge. This approach has merit when selling shaping power around an intermittent resource such as renewable energy.

However, even though the daily demand charge is a useful construct, it is, unfortunately, inadequate for reasonably implementing Senate Bill 12 because it is not granular enough. Consider what occurs for a Schedule 32 customer that is purchasing solar energy for delivery to its premises. Even though the solar resource will be available and providing reliable capacity for much of the on-peak period, <u>the daily demand charge approach realistically will not provide this customer any credit at all for avoiding generation capacity</u> because daily billing demand will be measured based on the customer's maximum shaping demand during the on-peak period, which, given RMP's definition of the on-peak period (7 am – 11 pm M-F winter, 1 pm – 9 pm M-F summer) will always occur after the sun has gone down. The upshot is that under the rate design proposed by RMP for shaping power, many Schedule 32 customers would be doomed to receive very little credit, if any, for avoiding RMP's generation demand charges, even when the renewable resource the customer is importing provides reliable capacity during much of the on-peak period. This result is largely an artifact of the definition of the on-peak period and the definition of daily billing demand.

Q. Do you believe this result is consistent with the requirements of the statute?

A. Substantively no. As I discussed above, the statute requires that any kilowatts of electricity delivered from the renewable energy facility that coincide with the contract customer's monthly metered kilowatt demand measurement must be excluded from the customer's utility bill. While RMP's approach may technically comply with this requirement (because of the definition of billing demand), as a practical matter, under RMP's proposal, many Schedule 32 customers will receive very little credit against their bills for the capacity they are importing.

Q. What is your proposed remedy for this problem?

A. This problem can be remedied by making the daily demand charge more granular, i.e., by converting it into an hourly demand charge (which I call the "hourly on-peak shaping charge.") By doing so, the Schedule 32 customer would receive a pro rata credit for the renewable energy capacity the customer imports during the on-peak period.

Q. Why is this approach reasonable?

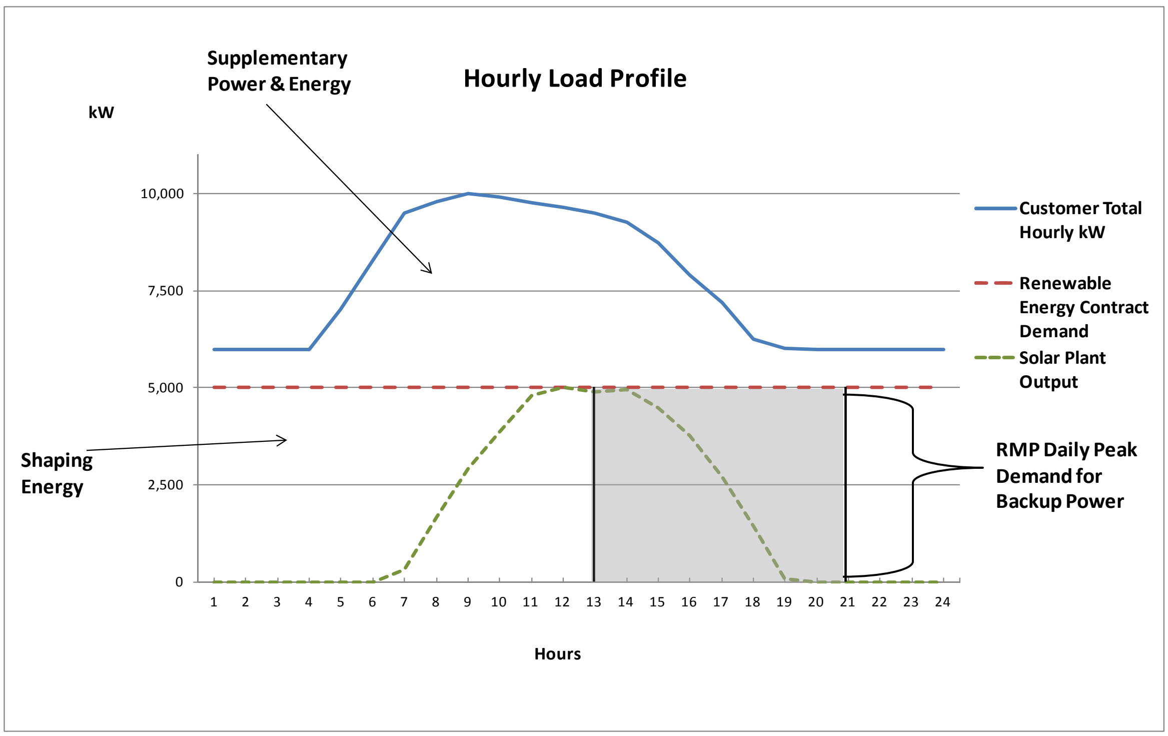
A. This approach is reasonable because it allows Schedule 32 customers to receive credit for the capacity they are "bringing to the table" that is in direct proportion to its availability during RMP's on-peak hours rather than having recognition of this real capacity benefit negated through the artifacts of how daily billing demand and the RMP on-peak period are defined.

To see this point, it may be useful to take a step back and look holistically at what could be a prototypical Schedule 32 customer. In Figure 1 below I have depicted a hypothetical Schedule 32 customer that is importing power from a solar resource. The contract demand for the solar resource is assumed to be 5,000 kW. The shape of the generation output for the solar resource is adapted from

RMP's example output for a solar facility in June included in the Company's workpapers in this case. The customer's overall peak demand is around 10,000 kW. Its assumed load factor during on-peak hours (Hours 13-21 in the diagram) is 80%, which is typical for a Schedule 9 customer.

Figure 1

Load Profile for Hypothetical Schedule 32 Customer Importing Solar Power



The customer's supplementary energy requirement is the area between the Customer Total Hourly kW curve and the Renewable Energy Contract Demand of 5,000 kW. The customer's shaping energy requirement is the area between the Renewable Energy Contract Demand of 5,000 kW and the Solar Plant Output.

Under RMP's proposal, the customer's daily peak billing demand is the maximum vertical distance between Renewable Energy Contract Demand of 5,000 kW and the Solar Plant Output. Because the solar plant's output reaches zero prior to the end of the on-peak period, the daily peak billing demand is always the maximum 5,000 kW, even though, as shown in Figure 1, the solar plant provides a substantial amount of capacity during the on-peak period. My recommended approach simply recognizes the value of this capacity on a pro-rata basis.

Finally, there is a fundamental reasonableness test that should be applied to the calculation of the hourly on-peak shaping charges, namely: do the charges produce the same revenue as the customer's otherwise applicable rate schedule in a month in which the renewable energy resource is unavailable for the entire month? In the case of my proposal, the rates are designed to produce exactly this result for the targeted load factors discussed in further detail below. Indeed, both RMP's daily demand charge and my recommended hourly on-peak shaping charge pass this test. The difference between the proposals is that my recommended approach produces more reasonable results when the renewable resource is operating as anticipated and the customer must purchase shaping power on a regular basis.

Q. Under your proposal would Schedule 32 customers also pay the backup energy charges proposed by RMP for shaping power in addition to the hourly on-peak shaping charges?

A. Yes. My recommended hourly on-peak shaping charge is a substitute for the backup *power* charges proposed by RMP. The backup *energy* charges proposed by RMP would still apply (although they are more accurately characterized as "shaping energy charges").

Q. What load parameters did you use in calculating your recommended hourly shaping charge for transmission voltage customers?

A. My recommended hourly shaping charge is equal to the monthly generation demand charge that a Schedule 9 customer would pay at a 90.26% on-peak load factor in the summer and an 89.69% on-peak load factor in the non-summer period, divided by the number of monthly on-peak hours in the summer and non-summer period, respectively. This calculation is limited to the generation portion of the demand charge because the Schedule 32 customer would already be fully compensating RMP for delivery services for its renewable energy contract demand (transmission and generation) through the delivery facilities charges. This calculation is shown in UAE Exhibit 1.2, page 1.

Q. Why do you use a 90.26% summer on-peak load factor for this calculation?

A. Please refer back to Figure 1. The portion of the customer's load that is relevant for this calculation is the shaded area in this diagram. The shaded area corresponds to the hours and customer load that are potentially subject to the backup power charge. In this example, it is the 5,000 kW of Renewable Energy Contract Demand during Hours 13 through 21. It is important to note that for many Schedule 32 customers, this shaded area is likely to correspond to a very high load factor, particularly to the extent that the customer contracts for renewable energy for only a portion of its overall peak demand (as seems likely). In the example, the load factor depicted in the shaded area corresponds to a load factor of 100% because the customer is assumed to always be consuming at least 5,000 kW of power during on-peak hours.

For purposes of calculating the hourly shaping charge, I selected a load factor that was midway between the theoretical maximum of 100% and the average monthly load factor during on-peak hours, which, on average, is the logical minimum load factor for the shaded area. Based on data provided in RMP's most recent general rate case, I calculate that the average monthly load factor during on-peak hours for a Schedule 9 customer is 80.52% during summer months and 79.38% during non-summer months. These calculations are shown in UAE Exhibit 1.2, page 3.

Q. What load parameters did you use in calculating your recommended hourly shaping charge for primary and secondary voltage customers?

A. Using the same methodology I described above for Schedule 9, I calculated the hourly shaping charge for primary and secondary voltage using a Schedule 8 on-peak load factor of 86.55% in summer months and 83.50% during non-summer months. This calculation is shown in UAE Exhibit 1.2, pages 2-3.

Q. Earlier in your testimony you recommended that the Commission not adopt RMP's proposed generation backup facilities charges. Does elimination of

this charge impact the calculation of RMP's daily demand charge (i.e., backup power charge) or your recommended hourly shaping charge?

A. Yes. If the generation backup facilities charges are adopted as proposed by RMP, then these charges must be a credit against either RMP's daily demand charge (i.e., backup power charge) or my recommended hourly shaping charge. RMP has already included this credit in the calculation of its daily demand charge, so if the generation backup facilities charges are eliminated, but the daily demand charge retained, then the daily demand charge rate would need to be increased to reflect removal of this credit. Alternatively, if the generation backup facilities charges are not eliminated, but the hourly shaping charge I am recommending is adopted, then the hourly shaping charges I am proposing here would need to be reduced to reflect the appropriate credit from the generation backup facilities demand charge.

SUMMARY OF RECOMMENDED SCHEDULE 32 RATES

Q. Can you please provide a summary of your recommended Schedule 32 rates?

A. Yes, my recommended Schedule 32 Step 1 rates are shown in Table 1 below. My recommendation for Step 2 rates is to increase these rates by 1.47% for transmission voltage and 1.03% for primary and secondary voltage to comport with the size of the Step 2 increase approved by the Commission in the recent general rate case.

Table 1
UAE Recommended Schedule 32 Charges

			Step 1 Rates
Customer Charge			See testimony
Administrative Charge			See testimony
Delivery Facilities Charge			
	Secondary Voltage		\$7.82/kW-mo.
	Primary Voltage		\$6.68/kW-mo.
	Transmission Voltage		\$3.79/kW-mo.
Hourly On-Peak Shaping Charge			
	Secondary Voltage		
		Summer	8.3724¢/kWh
		Non-Summer	2.8216¢/kWh
	Primary Voltage		
		Summer	8.3724¢/kWh
		Non-Summer	2.8216¢/kWh
	Transmission Voltage		
		Summer	7.9371¢/kWh
		Non-Summer	2.5444¢/kWh
Shaping Energy Charge			Sch. 6, 8, 9
Supplementary Power and Energy			Sch. 6, 8, 9

Q. Does this conclude your direct testimony?

A. Yes, it does.