BEFORE
THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate	)	
And Refine Procurement Policies and	)	R.10-05-006
Consider Long-Term Procurement Plans	)	

REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON RENEWABLE INTEGRATION MODELS

According the Administrative Law Judge's September 8, 2010, Ruling Requesting Comments on Renewables Integration Models, as updated by E-mail ruling dated October 1, 2010, the California Independent System Operator Corporation ("ISO") hereby submits reply comments to some of the issues raised by parties in their initial comments, as well as responses to the questions posed in the ALJ's E-mail.

A. Introduction

At the August 24-25, 2010 Commission workshops in this proceeding, the ISO presented and described a statistical methodology to determine system operational requirements and presented results (labeled Step 1) for its 33% RPS renewable integration study. The ISO also provide a preliminary review of methodology and inputs into production simulations being developed for that study (labeled Step 2). Since that time, the ISO has completed a study of the 20% RPS integration requirements for 2012 that generally follows the same methodology as the 33% RPS study and, as noted in brief initial comments, can help benchmark some of the 33% RPS study results.[1] The

[1] ISO comments at 3; http://www.caiso.com/2804/2804d036401f0.pdf

Commission has now scheduled a second workshop for October 22, 2010 at which the ISO intends to provide calibrated results for the 33% RPS reference case production simulation as well as several sensitivity results and a comparison to the 20% RPS in 2012 results. Additional details and a technical appendix describing both steps of the methodology also will be made available to the parties prior to the workshop.[2] Recognizing the uncertainties involved with forecasting a ten year future, it is expected that the validated results of the 33% RPS study addressed at the workshop will provide an understanding of the operational challenges and needs associated with meeting the 33% RPS requirements and give the Commission the tools needed to adopt an LTPP methodology.

At the outset, the ISO notes that many parties have referred to both the ISO and the PG&E analyses as "Renewable Integration Models" (RIM). In actuality, there is no single "RIM" and the PG&E and ISO models are quite different. The ISO is running a renewable integration model that is not a single application but consists of studies that are evolving and are intended to develop a series of operational tools. PG&E's model is single application that can be run by various parties. To avoid further confusion associated with calling both models "RIM," the ISO suggests that its studies be referred to as the ISO's Renewable Integration Analysis (IRIA).

B. Reply to Specific Comments

1. The ISO Will Work With Parties To Provide Access To Modeling Data.

[2] The ISO intends to post an Appendix to the 20% RPS study that will provide additional details about aspects of the 33% RPS methodology. The website reference will be provided to the parties prior to the workshop.

Several parties, including TURN, the California Energy Storage Alliance (CESA) and DRA, have expressed concern that insufficient information has been provided about the ISO's 33% RPS model and, accordingly, parties are unable to validate the methodology.[3] These parties point to Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure and argue that, should the Commission decide to use the ISO's RPS model as a basis for making a decision in this proceeding, parties must be given information sufficient to afford replication of the model's assumptions, algorithms and outputs. DRA has gone so far as suggesting that an independent third party verify the ISO model, and that "verifying, vetting, validating and reviewing" the model to be used in this proceeding will be such a lengthy process that the model results probably will not be available for use in the current 2010/2011 procurement cycle.[4]

As noted above, the ISO intends to provide additional modeling details at the October 22 workshop and in written materials. Furthermore, upon request by individual parties, the ISO will make every effort to comply with Rules 10.3 and 10.4 by making the database available to requesting parties and assisting parties to understand the linkage between input assumptions and output results. However, as has been the case in other Commission proceedings, for the production simulation analysis the ISO uses a commercially available software program known as "PLEXOS." Parties seeking to replicate the ISO results must make individual arrangements with the software vendor to use this model, or utilize a comparable production simulation software product, to run the analysis.

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[3] See, *e.g.* TURN at 3; DRA at 14-16; CESA at 7.
[4] DRA at 18.

Nonetheless, the ISO does not believe that model validation should delay the use of the system needs information that will be generated by the model beyond the current procurement cycle. The ISO is in the process of calibrating the study results and will share this validation information at the workshop. Furthermore, the ISO intends to use its study results, including the 20% RPS study and 33% RPS studies, as well as other analysis by the ISO and other parties, proactively to make its own operational and transmission planning decisions, as well as market product proposals.[5] Accordingly, the ISO will work with Commission staff and the parties to provide the level of understanding needed to move forward on the current schedule.

2. The ISO Will Evaluate The Possibility Of Modeling Large-Scale Storage As Part Of A Sensitivity Scenario.

CESA criticizes the ISO's model for failing to take into account energy storage-related resources as part of the Phase 1 effort. CESA urges the ISO to conduct the Phase 2 modeling concurrently with Phase 1 and to include large-scale energy storage such as compressed air, pumped hydro and battery energy storage as potential solutions to the impacts of renewable generation.[6]

The ISO notes that it has always been the intent to consider other solutions in Phase 2, as CESA seems to concede. That phase is envisioned to look at a potential range of solutions including solar and wind production management (e.g. spilling wind or reducing solar output by defocusing solar thermal plant mirrors), solar thermal with storage and/or supplemental firing, system level storage (large and small), increased flexibility from existing resources, revised inter-Balancing Authority Area scheduling

[5] See, *e.g.* "Renewable Integration: Market and Product Review Phase 1" September 30, 2010 http://www.caiso.com/2821/2821c31a21680.pdf
[6] CESA at 6.

time lines, etc). For each of these options, the first step that is needed is to develop an appropriate way to reflect them into the Step 1 and/or Step 2 analysis. The Step 1 and Step 2 models are currently capable of modeling aspects of these sensitivities and some have been done in preliminary form. For example, the Step 1 analysis has examined sensitivity to assumptions about forecast error, which has a significant effect on the results but assumes technological change. However, some of these options are likely to require some custom modeling approaches to adequately capture their flexibility and there are certain modeling limitations in the analysis. The ISO will attempt to address these new modeling requirements during the October to February time frame and, if possible, include an analysis of some of these options in the sensitivity scenarios discussed in the next section.

The ISO is currently modeling large scale projects such as pumped storage on an hourly basis in Step 2. Given a set of operational characteristics, the model can be extended to include other large-scale storage to address the operational and reliability needs that storage could provide. However, small-scale, energy-limited storage is more difficult to model in the current Step 2 modeling framework. One reason is that such units are primarily providing fast-response Regulation, which takes place on a minute-by-minute basis, and perhaps fast-response load-following at higher scale. However, these requirements are only modeled in the Step 2 model through a capacity reservation that does not recognize the value of fast response. In the simplest extension, the ISO could assume some MW of generic capacity dedicated only to Regulation and load-following as a proxy for such storage resources. On the other hand, the Step 1 analysis calculates generic Regulation and load-following capacity requirements, ramp rates, and ramp duration, which is valuable information for storage providers. In sum, explicitly modeling storage on various scales is a challenge that will require further work.

3. The ISO Will Be Able To Run Three Additional Scenarios By the End of February, 2011.

Item 5 of the Staff Proposed Data Needs requests that parties provide comments on whether the RPS integration model selected for use in this proceeding should be capable of results for seven scenarios. With respect to this item, the ISO agrees with TURN's comment that the results from all seven scenarios would be of value, but that the complete list is "quite ambitious" given the time needed for scenario development, processing and simulation.[7]

The ISO understands that the Staff is developing a new set of renewable resource scenarios that will be made available shortly. Based on the expectation that this data will provided in October, the ISO anticipates that between the end of October and the end of February, Step 1 and Step 2 analyses can be conducted for 3 new scenarios, including sensitivity validation runs. Based on the objective to determine the "least regrets" procurement needs for this round of procurement, the ISO recommends the following scenarios be run to assist in identify the trajectory of potential needs as the renewable integration levels increase:

1. 33% Expected Trajectory (with reasonable level of imports of renewable incorporated).
2. Midpoint Trajectory (similar to a 27.5% case) that reflects the expected renewable build-out in 2015-2016.
3. High DG-2020 (this case may be important to cover the possibility of larger quantities of DG such as rooftop PV occurs).

[7] TURN at 4.

In addition, the ISO notes that it will likely be necessary to conduct an analysis of the first year in which additional fleet flexibility needs are expected to materialize.

4. The ISO Will Consider the Appropriate Mix of Out-of-State Renewable and Flexible Imports.

The Western Power Trading Forum (WPTF) suggests that Step 1 of either the ISO or PG&E methodology include a consideration of out of state renewable resources that will be firmed and shaped before being delivered to the ISO BAA.[8] According to WPTF, forecast errors and the amounts of shaped imports are the biggest drivers of operational flexibility requirements. WPTF also recommends that the Commission consider the extent to which out of state resources can provide flexibility services through a variety of means, thus lessening the need to rely entirely on the ISO's market or resources procured through the Commission's process.

The ISO has modeled, in Step 1, a portion of the out of state renewable resources as non-variable production so that they do not contribute to the requirement for in-state Regulation and load-following. Specifically, the ISO assumed that 70% of out of state resources should be modeled in this way and the remaining 30% as relying on ISO integration in the hour. The ISO believes that this is a reasonably conservative starting point assumption that could be refined based on actual practice. Thus, the ISO recommends that it is more important at this point to focus on estimating the various mixes and amounts of solar and wind that will be imported as well as the impacts of different potential import mechanisms. Such estimates should consider four potential conditions:

[8] WPTF at 6.

1) Imported resources are fully firmed and shaped and, as a result, such imports do not create a within –the- hour flexibility burden on the ISO.

2) Imported resources that are contingent firmed and shaped, in which case the sending BAA may make intra-hour scheduled adjustments to the deliveries based on the changes in the condition in host BAA and ability of the host BAA to balance these resources. Under these circumstances there will be some variability burdens the ISO will still have to manage.

3) Renewable resources that are not delivered at all but LSEs receive renewable energy credits. In this case the resource variability does not create an operational burden on the ISO BAA.

4) Imported resources are dynamically transferred into the ISO in which case the ISO will be responsible for the variability and uncertainty;

If the expected quantity of these different scenarios can be determined, the ISO can better shape the analysis considering the import renewable resources. The ISO suggests that this issue be further addressed at the workshop and that a mix of imported renewable resources with the characteristics outlined above be considered for inclusion in one of the resource scenarios to be evaluated between October and February.

5. Not All Dispatchable Resources Will Provide Needed Within-the-Hour Operational Flexibility.

Relying on Slides 73 and 78 from the ISO's August 24 workshop presentation, DRA created its own Table 1 at page 4 of its comments and concludes that "85.9% of resources that are currently available in California are dispatchable [for the 33% reference case]." This conclusion- that the ISO currently has sufficient flexible resources to meet the operational needs under a 33% scenario- is repeated throughout DRA's comments.

DRA misunderstands the dispatchability information provided in Slide 73 and has drawn an incorrect conclusion about the data about the current generation fleet. The reference in DRA's Table 1 to "dispatchable capacity" refers to resources that have some ability to have their output modified from hour to hour. Several of these resources do not provide for the flexibility to be modified in a way to provide the within-the-hour flexibility that is required to meet the regulation and load following needs that are developed in Step 1 and are input into Step 2. The resources in DRA's Table 1 that cannot provide Regulation and load following are the existing and new Demand Response and the Net Interchange which total 16,800 MWs. If these resources are removed as "dispatchable capacity," the percentage of existing resources that are truly dispatchable and are able to meet the within-the-hour regulation and load following requirements drop by 28% below the 85.9% figure referred to in the comments.[9]

6. The ISO Reference Case Models Existing Resource Flexibility as well as New Thermal Resource Flexibility.

Calpine raises concerns about whether the ISO's model will represent the full flexibility of existing resources that may be available without modification.[10] Specifically, Calpine notes that it is unclear whether the ISO model captures the differing ramp rates of combined cycle gas turbines (CCGTs) and potential increases to the dispatchability of Qualifying Facilities (QFs).

The ISO's reference case assumes large scale once through cooling retirements, as well as other units, and, for modeling purposes, these resources were replaced with new combustion turbines with updated flexibility characteristics. These existing and new CCGTs were modeled as dispatchable resources consistent with typical production simulation modeling. However, the ISO was not able to model them in the detail required to represent of all their configurations (e.g. CAISO's new Multi-Stage Generating ("MSG") Unit Modeling functionality). For example, the ISO did not model

[9] The ISO has not been able to determine how DRA arrived at the 85.9% dispatchability level.
[10] Calpine at 6.

CCGTs as having different ranges of operation and with the potential for different ramp rates for each range. Rather, as far as flexibility is concerned, the resources were modeled with a single ramp rate, based on typical average ramp rates, over a single dispatchable range. The ramp rate was set to provide an approximation of the ramping over the entire range. In addition, the CCGTs in the study have start-up (cold) and shutdown times that range from 2-5 hours for startup and 1-2 hours for shutdown.

The hydro systems of Northern and Southern California were modeled as a combination of run of river plants which have no dispatch flexibility and the remaining plants which are dispatchable. The mix of run of river and dispatchability was based upon the hydro operation in 2005. Pumped storage plants were modeled to allow starts in the pump and generate mode and to provide load following and ancillary services (Regulation and reserves) in the generation mode.

C. Response to Additional Issues

In the October 1, 2010, E-mail, ALJ Kolakowski identified seven topics upon which the Energy Division seeks further comment and discussion. It is the ISO's understanding that these topics will also be discussed at the workshop.

1. Data Used to Develop Wind and Solar Generation Profiles.

The source of the data used by the ISO for developing the wind production profiles for new wind resources used in Step 1 is NREL data for year 2005 for each CREZ (one or more data points within each CREZ) that contains wind generation. Existing wind resources were modeled using actual historical data. Additional details can be found in the ISO's draft technical appendix.

The source of the solar profile data is NREL historical irradiance data for 2005 from sites within or adjacent to the CREZs that contain solar plants. This data is processed by the NREL Solar Advisory Model to estimate hourly production for each solar plant in the study.

The production data was then used at different levels of aggregation for the Step 1 models (1-minute) and the Step 2 models (1 hour).

2. Adjusting Forecast Errors Associated with Renewable Generation to Reflect the Geographic Diversity of Generation.

Evaluating geographical diversity of forecast errors, rather than actual variability, is a research topic that the ISO attempted to advance in its current analysis, but for which further work needs to be done in the future. The ISO Step 1 model captures the effect of technological diversity on solar forecast errors because a specific model was developed to estimate forecast errors for 4 different solar technologies (solar thermal [in and out of state], solar PV, and distributed solar). However, due to a lack of forecast data in many of the CREZs where future wind and solar may be located, the model does not consider the effect of geographical diversity on wind and solar forecast error. That is, the model does not consider that some locations will have different forecast errors than others. The process of forecasting wind and solar is described in detail in ISO's draft technical appendix.

Note that the ISO models do account for the effect of geographical diversity on *variability*, because each resource was modeled in particular CREZ locations and so in any particular minute, if the wind and/or solar production is higher in one CREZ than another, the model does reflect geographical diversity. This applied to both Step 1 and Step 2.

3. Number of Standard Deviations Used to Select Values from Distributions of Flexibility Requirements.

The Step 1 model uses a statistical simulation based on hour-ahead forecast errors for load and wind/solar production and the 5 minute-ahead forecast errors for load along with a persistence model for wind and solar production (the solar persistence model was based on a clearness index). The forecast errors are a truncated normal distribution with a maximum and minimum error based on the higher of 3 standard deviations of the forecast errors or the maximum capacity of the plant. The results generated using these assumptions then further excluded the outlying 5% of the results.

The decision about whether to use a lower threshold for excluding results, such as removing 10% of the highest results using the ISO assumptions on the forecast errors, or only considering 2 standard deviations of the forecast errors, clearly has both operational and potentially reliability impacts as it implies that the ISO will not seek operational solutions for that range of possible ramp and Regulation requirements that is left out of the analysis. The ISO's initial decision to reject the 5% highest results was a proxy for Control Performance Standard 2 (CPS2), [11] which requires 90% compliance. Hence, there was a small safety margin of 5% coverage. Essentially, when the ISO does not comply with CPS2, it is effectively excessively leaning on the rest of the WECC interconnection and violating NERC reliability standards.

[11] The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document") http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf.

There are two important caveats. First, the CAISO is currently operating under a WECC Reliability-Based Control (RBC) field trial. Under RBC, there is recognition if a Balancing Authority Area Control Error (ACE) is supporting interconnection frequency, whereas CPS2 does not. Therefore, in cases where the Balancing Authority ACE is supporting the interconnection, RBC is less restrictive than CPS2. However, under RBC, the Balancing Authority ACE Limit (BAAL) becomes increasingly more restrictive than the corresponding CPS2 L_{10} limit as Interconnection frequency deviates further from 60 Hz. Second, the ISO also used an optimistic expectation of improvements in forecasting that reduced the operational requirements.

Hence, the ISO does not currently believe that adopting a different truncation of forecast errors to reduce the determination of operational requirements, or simply to reduce the distribution of operational requirements calculated under the original assumptions about forecast errors, is justifiable.

4. Should Day-Ahead Commitment be Included as an Operational Flexibility Requirement?

The ISO believes that RA resources along with existing commitment processes should allow for management of day-ahead forecast errors; however, this is a topic for further analysis. Nonetheless, although there is greater forecast error between the Day-Ahead and Real-Time Market, as long as the ISO has sufficient access to RA capacity, such forecast error consideration can be accounted for by committing and de-committing units when performing the Residual Unit Commitment (RUC) process and then continuously in rolling 15 minutes to 5-hour ahead unit commitment processes over the operating day. Through these processes, the ISO can commit additional resources to account for much of the forecast errors between the Day-Ahead and Real-Time, rather than creating an additional operational/flexibility requirement that would be enforced in the real-time. Importantly, the RUC as currently designed can procure unit start-up to minimum load with an option call on generation capacity needed for operational purposes without buying energy. Hence, the ISO will have sufficient time to adjust its day-ahead commitment based on updated information such that the impact of the day-ahead forecast error on actual operational readiness will be less than would be anticipated if no such adjustment was assumed. Moreover, by 2020, there may be other changes to the market and scheduling processes that attempt to further reduce the impact of day-ahead forecast errors on unit commitment.

5. Is It Appropriate to Treat Separate Operational Flexibility Requirements as Additive?

This question could have the following dimensions:

1. Are the quantities of Regulation and the proposed load following additive?
2. Is the proposed load following needed in addition to the spin and non-spin operating reserves?
3. Is the proposed load following needed in addition to the operational flexibility necessary to meet the hourly schedule change?

The answer to these questions may differ for each of these scenarios. The ISO believes that load following operational requirements should be additive to Regulation requirements because Regulation is capacity that is under direct control of automatic generation control (AGC) to respond to variability needs within a 5 minute interval. This is in contrast to load following which is effectively accounting for the amount of operational capacity necessary to meet the difference between the hourly average net load[12] and the average 5 minute net load. Therefore these two flexibility requirements are appropriately additive because they are expected to perform in different timeframes.

With regards to load following being additive to the spin and non-spinning reserve operating reserve obligations (question number 2), the operating reserve requirements are required to be prepared to meet a contingency and are based on current NERC and WECC requirements. While forecast error associated with load, wind and solar may be similar to a contingency, historical operating practices have not included resource variability or forecast errors as contingency. If the NERC/WECC were to recognize resource variability and forecast errors as a contingency event, it may be appropriate to consider the flexibility needs associated with such variability and error not as additive but rather overlapping where the current definition of contingency reserves becomes a lower bound of reserves and the reserves needed for variability and forecast error are the upper bound on such reserves. Another reason that these two types of reserves are appropriate to consider as additive are the ramping and availability characteristics. Spinning and Non-Spinning reserves are traditionally held in reserve and are not available for dispatch except for the occurrence of an event. Furthermore, when the event actually occurs, such reserves must be deployed within 10 minutes to satisfy NERC's Disturbance Control Standard (DCS). Flexibility associated with variability and forecast error are not necessarily held in reserve waiting for an event. Instead, this flexibility should be made available to balance the system in real-time regardless of an event. Furthermore, the flexibility may not have to be deployed in 10 minutes. Further study is necessary to determine the ramping time needed for load following in high renewable scenarios, but the proposed methodology assumes that the load following

[12] Average net load is the amount of load net of wind and solar generation.

reserves must be able to be deployed within 20 minutes. That is, each load-following resource can supply in each hour its ramp rate times 20 minutes, up to its available capacity. Based on the Step 1 results, a 20 minute ramp capacity requirement covers most ramping needs even for shorter duration ramping events.

The last question is whether the total hourly load following capacity requirement calculated in Step 1 is needed in addition to the capacity reserved for the hourly average change in load or whether a quantity net of that amount would be sufficient. Since the ISO will not know exactly when the load following reserve will be needed within the hour, one could argue that these values are necessarily additive. However, it does also seem appropriate to consider at least a portion of the load following flexibility requirements as being satisfied by that portion of the hourly load difference that occurs within the hours. Since we estimate that hourly schedule to be approximately symmetric across the hourly boundary, it may also be appropriate to recognize that half the hourly schedule change in the same direction as the direction of load following service may overlap with the load following requirements. Therefore it may be appropriate to reduce for that hour, the load following capacity requirements by half of the hourly load schedule change in the same direction. However, other hours may not allow such an adjustment. The ISO is investigating such an approach.

6. Use of Hourly Instead of Sub-Hourly Time Intervals for Determining Operational Flexibility Requirements.

The 33% renewable integration study methodology uses sub-hourly statistical analysis (Step 1) for determining *hourly* operational requirements (regulation and load-following). The hourly operational requirements determined in Step 1 are then used as inputs to the hourly interval production simulation analysis of Step 2. An alternative approach would be to perform sub-hourly production simulation, typically on a 5-minute basis similar to the ISO's real-time dispatch. However, a significant obstacle to such an analysis is that it is computationally intensive, and likely cannot be performed for more than a few sample days. The advantage of a sub-hourly production simulation approach is that it can test whether the units available can not only supply the capacity needed to provide load following in 20 minute ramp periods but also the speed of ramps in each 5-minute dispatch interval. Hence, it would be expected that the simulation could find operational constraints that an hourly model might not. The ISO undertook such an analysis in its 20% RPS study.[13]

If this approach is used for sample days, there are two possibilities. One is a deterministic 5-minute analysis that simply conducts commitment and dispatch against the 5-minute intervals and then compares the result to the hourly model results. The more sophisticated approach as noted above is to conduct unit commitment under uncertainty on a day-ahead and hour-ahead basis with forecast errors, and then to dispatch the committed units against the 5-minute intervals. However, in order for sub-hourly production simulation to capture the statistical distribution of forecast error, the sub-hourly production simulation would need to be run multiple times using different random draws of day-ahead or hour-ahead forecast errors to ensure that a statistically sufficient range of conditions is considered. Since Step 1 analysis already captures the statistical distribution of the hour ahead forecast errors, the ISO would expect that the maximum operational flexibility requirements from the fleet will be similar to the maximum requirements established via Step 1 analysis. This hypothesis would need to be tested; if true, it would imply that the Step 1 analysis of intra-hour load following, which

[13] See sections 2.5.2 and 6 of the ISO 20% RPS Study, as well as the technical appendices.

is more efficient than production simulation, could suffice (when coupled with the hourly Step 2 model).

7. Are Historical Case Runs Necessary for Model Validation?

While historical case runs may be useful for calibration of the model, since the existing system in general has sufficient resource flexibility, the results of such a run may not be of much value and would be an expensive use of resources and time to perform. The ISO has performed 20% studies for 2012 and has also compared the amount of flexibility of the system in those studies with the actual system conditions in the current dispatch.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served, by electronic and United States mail, a copy of the foregoing Reply Comments of the California Independent System Operator Corporation on Renewable Integration Models to each party in Docket No. R.08-11-005.

Executed on October 11, 2010 at Folsom, California.

/s/ Anna Pascuzzo

Anna Pascuzzo

An Employee of the California Independent System Operator Corporation