PNNL - 27972

Pacific Northwest
NATIONAL LABORATORY

Applying the Transactive Systems Business Value Model to IRP

December 2018

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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Executive Summary

As part of the Transactive Systems Program at Pacific Northwest National Laboratory, a value modeling system was developed to support the evaluation of transactive systems. The technique is general enough to be applied outside transactive systems and to demonstrate this capability, a project was undertaken to use this value modeling technique as a means for modeling the valuation process undertaken by vertically integrated utilities when undergoing integrated resource planning (IRP).

IRP is the process by which vertically integrated utilities (those that both serve customers directly as well as manage and run generation assets to do so) regularly go through to demonstrate to their regulators that they have a plan to meet the expected future load of their customers in a least cost and compliant manner. Traditionally this has been primarily an issue of how many and of which types of power plants to build but increasingly has included alternative measures such as demand response programs. Increasingly, environmental regulations play a significant role in both determine what types of power plants can be built under current regulations as well as what retrofits or upgrades need to be made to existing plants to allow them to continue to operate.

Two use-case diagrams were constructed, one showing the showing the process by which IRP is carried out and another showing how a vertically integrated utility procures the resources it requires to meet load now and in the future. These diagrams help clarify the difference and provide a high-level outline of the two processes.

A class diagram was constructed to clearly define the types of actors that would be considered in this model and the relationships between them. This diagram tacitly indicates which types of actors are and are not included in the model which provides significant guidance in defining the scope of the model. The relationship between the classes/actors provides further indication of what areas of the model have higher levels of detail and by implication bear more significance in modeling the system.

Using the classes/actors defined in the class diagram, a business value diagram was constructed that defines the key value streams exchanged between the actors. This diagram provides a clear expression of the business case of the vertically integrated utility and who its counter-parties are during the process of meeting load. These value streams have not only to do with meeting the load but doing so in a manner that meets environmental regulations. Increasingly, IRPs have three key metrics to evaluate a given plant to meet load: net present value of revenue required, emissions, and renewable energy credits.

From this business value diagram, more detailed activity diagrams were formed that focus on a few of the key value stream exchanges, showing the process by which each party accrues value. These diagrams provide insight into the timing and sequence of the interactions in a way that the business value diagrams did not.

The transactive value model was found to be highly compatible with IRP and provided a clear, simple model of the analysis done during IRP and key metrics driving IRP decisions. In particular it highlighted a few key items that may or may not have been as clear prior to the development of the model. Specifically, the role of the environmental regulations has become increasingly important and two of the three key metrics by which IRPs are typically evaluated are environmentally focused. Additionally, though generally not acknowledged, the role of the investor was included in this model as they are an essential source of capital in building new power plants and cannot be ignored when defining the business case of the vertically integrated utility.

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1.0 Introduction

As part of the Transactive Systems Program at Pacific Northwest National Laboratory, a value modeling system was developed to support the evaluation of transactive systems. Transactive systems, by their nature, have a more complex set of business and information interactions than takes place in power systems today, and the value modeling system was designed to provide the level of rigor, clarity, and transparency needed to ensure the evaluation the transactive system was done appropriately. This modeling effort typically involves the identification of the entities (“actors”) involved in the operation of the system, the values they exchange, the process by which those values exchange and accrue to the individual actors, identification and definition of the metrics by which the operation of the system is evaluated, and once the analysis of the system operation is completed, the tabulation and examination of the values found for those metrics. Typically, most of these results are expressed as diagrams, showing the nature and timing/sequence of the value exchanges. By using this structured approach to define the system under study and the means by which it will be evaluated, the nature and goals of the system are more clearly communicated and understood.

The technique that was developed seemed general enough that it was speculated it could be applied to the integrated resource planning (IRP) process that some utilities perform, typically vertically integrated utilities as a part of the regulatory oversight of public utility or public service commissions (PUC/PSC). IRP is used by these utilities to justify the investment decisions they plan on needing to make over the next several decades and the complexity and level of rigor to conduct these studies well is generally similar to that of transactive systems. One of the tasks for the Transactive Systems Program during this year, then, was to explore the application of the value modeling to IRP and determine what usefulness, if any, it could provide both to those familiar and unfamiliar with IRP. This report provides a summary of the work performed and the results of attempting such a model development.

2.0 Overview of IRP

IRP refers to a utility planning process (typically vertically integrated utilities, VIUs) used to arrive at a preferred set of resources for meeting peak demand and energy needs, over a planning period (typically fifteen to twenty years). This analysis is typically required of the VIUs because they both serve customers directly and build transmission and generation assets using revenue derived from those customers. Additionally, many of these VIUs are investor-owned with the capital being raised from the investors used to fund the construction of the large transmission and generation assets with the return from the investors being collected from customers. Thus, there is an incentive on the part of the VIU to build capital-intensive assets to increase the profits to be returned to the investor/owners, even if construction of said assets are not in the best interests of the customers. The IRP process is used by regulators (public utility or public service commissions) to force the VIUs to objectively evaluate a wide spectrum of ways to meet the expected load over the next decade or two and find the least cost means of doing so (Hirst et al. 1990, Lazar 2016).

Deregulated utilities – those utilities that don’t own generation or transmission and are only responsible for distribution operation and maintenance and billing – don’t typically perform IRPs because they are only responsible for electricity delivery and billing and other entities are responsible for procuring power. In deregulated states, procurement plans or long-term plans that are less focused on asset construction and more on power acquisition are more common.

When evaluating possible ways of meeting the expected load, utilities typically construct collections of possible supply-side and demand-side resources into a "portfolio" of resources. The process of building these portfolios varies widely from utility with some doing significant simulation and analysis and others doing more general or rough estimates of what might be required; these portfolios then form the basis of the IRP analysis. IRPs are typically conducted in an iterative manner in which utility analysts examine multiple alternative future conditions and alternative portfolios for meeting the range of future conditions. Each portfolio of resources is evaluated in terms of a number of metrics typically relating to cost (the revenue that will be required from ratepayers), emissions, and ability to meet regulatory requirements (some of which relate to renewable energy). IRPs are typically performed every 2-4 years.

Each IRP reflects a given utility's specific planning environment. The utility's existing resources and potential range of future resources are affected by existing or expected state and federal laws and regulations, and other factors that define the utility's environment. Thus, for a utility facing Renewable Portfolio Standard (RPS) requirements, the IRP would in part reflect the need to meet the RPS in future years. For a utility with significant holdings of coal-fired generation, the IRP would reflect the known or expected ways air quality requirements will affect their resources. Finally, a utility's planning environment may be affected by other characteristics, such as atmospheric climate and customer composition and density. Risk assessment of each of the portfolios is often accomplished through a stochastic analysis, varying fuel and energy prices and other location-specific variables such as the state of the reservoirs for locations with a high number of hydropower generators.

IRPs are typically conducted by utility staff with support from outside consultants in the development of specific technical analyses such as resource potential studies for energy efficiency or demand response. The Regulatory Assistance Project (RAP) notes that IRP processes usually include at a minimum the following: (Wilson and Biewald, 2013)

- forecasting future peak demand and energy loads, including required or desired reserve margins,
- identifying potential resource options to meet future loads,
- modeling possible resource mixes to identify the optimal mix of supply- and demand-side resources to minimize future electric system costs while taking into account known and quantifiable risks and uncertainties,
- receiving and responding to public input and comments, and
- creating and implementing the resource plan based on the results of the analyses and public input. (Wilson and Biewald, 2013)

(APS 2017, PacificCorp 2017a, PacificCorp 2017b, Xcel Energy 2016a, Excel Energy 2016b, TVA 2015, Dominion Energy 2018, FPL 2018) form a representative sample of recent IRPs from a variety of utilities.

IRP, while addressing supply- and demand-side resources, has tended to not address the full range of supply and demand options generally included under the heading of distributed energy resources (DER): energy efficiency, demand response, batteries, thermal energy storage and other virtual battery approaches, electric vehicles, solar photovoltaics, combined heat and power, and other distributed generation such as wind. Many utilities consider some subset of the full range of DERs into account in IRP, often in the form of projected reduction to average loads. It is common for stakeholders focused on renewable energy in the IRP processes to argue the methods being used by utilities to project penetration levels and DER contributions to peak reduction are insufficient and costs of these resources are too high. At the present time, handling of DERs within IRP are generally seen as emerging, incomplete and needing improvement. (Reid et al. 1990)

3.0 IRP Value Model Overview

IRP is generally performed by actors who are internal to the utility preparing the IRP with the resulting plan serving as a blueprint for future resource acquisitions, many or most of which involve transactions between the utility and its business partners (vendors, energy markets, etc.) and customers. Value modeling is a tool for defining the nature of those transactions. Each portfolio of resources under consideration potentially has different value exchanges associated with them as the parties involved in acquiring the necessary resources shifts from portfolio to portfolio. This section introduces value modeling and then describes the specific application of value modeling to IRP.

3.1 Introduction to Value Modeling

The Transactive Systems Program value modeling developed by Pacific Northwest National Laboratory (PNNL) has the general goal of ensuring the study of a given system is done in such a way so as to produce valid and meaningful results. This is accomplished through a relatively rigorous process that is intended to clearly document the system under study as it is being defined and the study is being planned. When fully developed, the value model defines the value exchanges between actors in the system, the activities associated with those value exchanges and the process by which the values accrue to each actor, the metrics that will be used to evaluate the performance of the system, and the corresponding measurements of the system behavior (through any means of analysis) needed to support the calculation of those metrics.

Within the Transactive Systems Program modeling, PNNL has developed several different types of diagrams to illustrate the system being modeled. In this review of IRP, PNNL focused on the use of four types of diagrams – use case diagrams, class diagrams, business value diagram, and activity diagrams to capture the exchanges that take place between the utility and external parties or actors. The value model in general is typically expressed through a number of artifacts which focus on various specific components of defining the system under study. These range from diagrams formed using Unified Modeling Language (UML) conventions to ledgers comparing performance metrics of the system with and without the components under test included. When performing a study of a specific system this suite of artifacts (diagrams and ledger) is useful in providing the rigor and clarity needed to well-define the system and its performance.

The four diagrams developed provide a variety of perspectives on the IRP process by emphasizing certain aspects.

- **Use case diagram:** The use case diagram provides a high-level view of the activities of one or more actors in the system emphasizing the tasks typically executed, the goals to be accomplished, or the problems to be solved by engaging in these activities.
- **Class diagram:** The class diagram shows the nature of the relationships between the actors (expressed as classes) in other parts of the model and the number of the various actors included in the model. Sub-class and component relationships are generally the types of relationships most importantly expressed in this diagram.
- **Business value diagram:** The business value diagram provides a high-level view of the value exchanges between central actors in the system under consideration. By focusing on the value exchanges of one or more actors, a clearer and simpler view of the central business case is produced.

- **Activity diagram:** The activity diagram shows the process by which the values expressed in the business value diagram are accrued and provides more detail about how a given actor executes the use cases detailed in the use case diagram. These diagrams are similar in nature to flow charts and can show both value exchanges as well as information transmission between actors.

In addition to these diagrams, the key metrics that are typically used when comparing portfolios are discussed.

3.2 IRP Value Modeling Assumptions

The following assumptions were made when developing the value model. These assumptions define both how the value diagrams should be interpreted and how the actors in the diagrams are assumed to act.

- Only actors and values shown on the diagram are modeled. Utility IRP analyses cover long-term (15 – 20 year) planning horizons, frequently entail large geographic areas and/or significant population centers, and include large numbers of generating and demand-side resources. For this reason, the utility performs the IRP analyses with a minimum of specific details. When the value model was created, PNNL attempted to model the IRP process and analyses as closely as possible while attempting to capture the necessary actors and values. If it's not shown, it should be assumed to be not modeled.

- Only value interactions that are determined to be significant in magnitude are shown and hence modeled. For example, if the utility IRP selects more wholesale transactions, such might cause the utility to hire an additional scheduler or power trader. The cost of one or two employees would be a very small fraction of the cost of the power they buy, sell or schedule, and thus would not be represented in the value model.

  The "owner costs" used in modeling generating resources includes a large number of relatively insignificant costs[1] that are not included in the model. The total of this cost category varies from six percent to twenty-two percent of total overnight plant construction cost (EIA 2016). These costs are all, by definition, included in the cost of new generating facilities and are not shown individually. Similarly, land acquisition related to construction of transmission facilities[2] can range up to 10 percent of the cost of the transmission facility (Mason et. al., 2012). Land costs, permit costs, etc., are generally a small to very small percentage of the total cost, and rather than exploding dramatically the number of actors to account for items which are individually not significant, the value diagram focuses on the main actors and assumes that minor cost categories are captured within the larger category.

- Only value interactions that have been determined to be under consideration are shown. Options that are *a priori* determined to be infeasible are not shown. For example, though geothermal and

[1] The U.S. Energy Information Administration's 2016 report entitled *Capital Cost Estimates for Utility Scale Electric Generating Plants* lists the following under Owners Costs: development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system.

[2] Transmission planning generally takes place outside of the IRP process although in some cases generating and transmission facilities are proposed jointly because the location of the generator makes power delivery infeasible without the transmission facility.

biomass generation facilities do exist, they are generally not feasible options to meet any significant amount of load and were not included in this value model.

- Only non-cynical utilities were assumed to exist. It is assumed that utilities will choose to seek compliance with regulations and not willing choose to ignore regulations. Thus, even in hypothetical cases where the least cost method of securing the energy would be to ignore regulations and pay fines, we assumed utilities will generally seek compliance with regulations. This applies to environmental regulations like emissions restrictions as well as RPS requirements.

- Emissions and RPS will continue to be a significant concern for the foreseeable future. In their most recent IRPs, utilities generally assumed the Environmental Protection Agency's (EPA) Clean Power Plan (CPP) would be put into effect and the IRPs analyzed compliance paths for the CPP. In analyzing the CPP, utility IRPs looked at several possible outcomes including carbon taxes and mass requirements (limits on the pounds or tons of emissions per unit of time or output). With the CPP being put on hold by the U.S. court system and the EPA announcing a proposed replacement for the CPP, utilities' next IRP will attempt to quantify emissions regulations to which they expect to be subjected in the future (Dominion Energy 2017). In considering these uncertainties, utilities will model their best estimates of the range of reasonably possible regulatory outcomes and develop plans that meet the requirements at the least cost and/or with the least amount of risk of failure to meet the requirements. This is primarily expressed in the value model through metrics focused on emissions and RPS standards.

- Investors are included as actors. The impact on investors is one difference between generating resources, and demand-side resources and wholesale purchases. The current common utility rate-setting model includes provisions for return to stockholders based on investments that can be put into rate base. Generally, rate base equals total plant in service less accumulated depreciation, plus allowances for operating capital, stores and supplies, fuel supplies, and spare equipment. Investments made in equipment on a customer's premises generally does not add to rate base nor does power purchased in wholesale markets. Thus, the resources selected – a new generating plant vs a DSM program vs a market purchase – makes a difference in the rate base which in turn makes a difference in the money earmarked in ratemaking processes for investors. Including this in the value diagram is important and could lead to a useful dialog, increased transparency and alignment.

- Distributed generation is not considered because it is not a dispatchable resource to the utility. Currently, the majority of utilities treat distributed generation within the distribution system as load reductions for purposes of IRP. Rooftop solar, community solar, backyard wind and other small generation is generally outside of the utility's control. It is not dispatchable. The most progressive utilities in states with the most aggressive RPS requirements may use price signals to try to shape distributed generation in various ways, but the pace of installation, the locations, the sizing, and most factors of importance remain largely if not entirely outside of the control of most utilities. Thus, distributed generation is largely not explicitly included as a resource in IRPs at present and it was not included on the business value diagram.

  Increasingly, distributed generation is being included in distribution system planning as a non-wires alternative to new construction. Distribution planning and IRP are separate activities with the aforementioned states with aggressive RPS requirements currently working on ways of merging the two processes.

- Transmission plant construction is a consideration in new plant construction. Traditionally, new generating plant costs included tradeoffs between the distance covered by transmission facilities to deliver power to load centers and the distance fuel (coal, natural gas, etc.) must be transported. Increasingly, transmission is associated with the remote locations offering the best opportunities for wind and solar resources. Transmission plant construction therefore becomes an input in the cost assessment for generation. While transmission planning is most often separate from IRP it is included in the value diagramming because of the impact transmission costs can have on the IRP results.

3.3 Use Case Diagrams of the IRP Process

An IRP includes a wide range of actors and transactions. To help clarify some of the elements of the business value diagram, a use case diagram was prepared to illustrate the IRP process in general. Figure 3.1 shows the IRP use case diagram. The diagram shows actors (e.g., the Analyst) performing actions such as configuring the IRP, stating or forecasting economic factors, and numerous other actions. The use case diagram indicates these processes includes a number of actions (shown by "<<include>>" above the arrows). It also indicates some actions precede other actions. Thus, the analyst must configure the IRP by, among other things, compiling the inputs, projecting the future electricity demand, predicting and modeling the applicable regulatory policies, and the assembling the list of feasible resources.

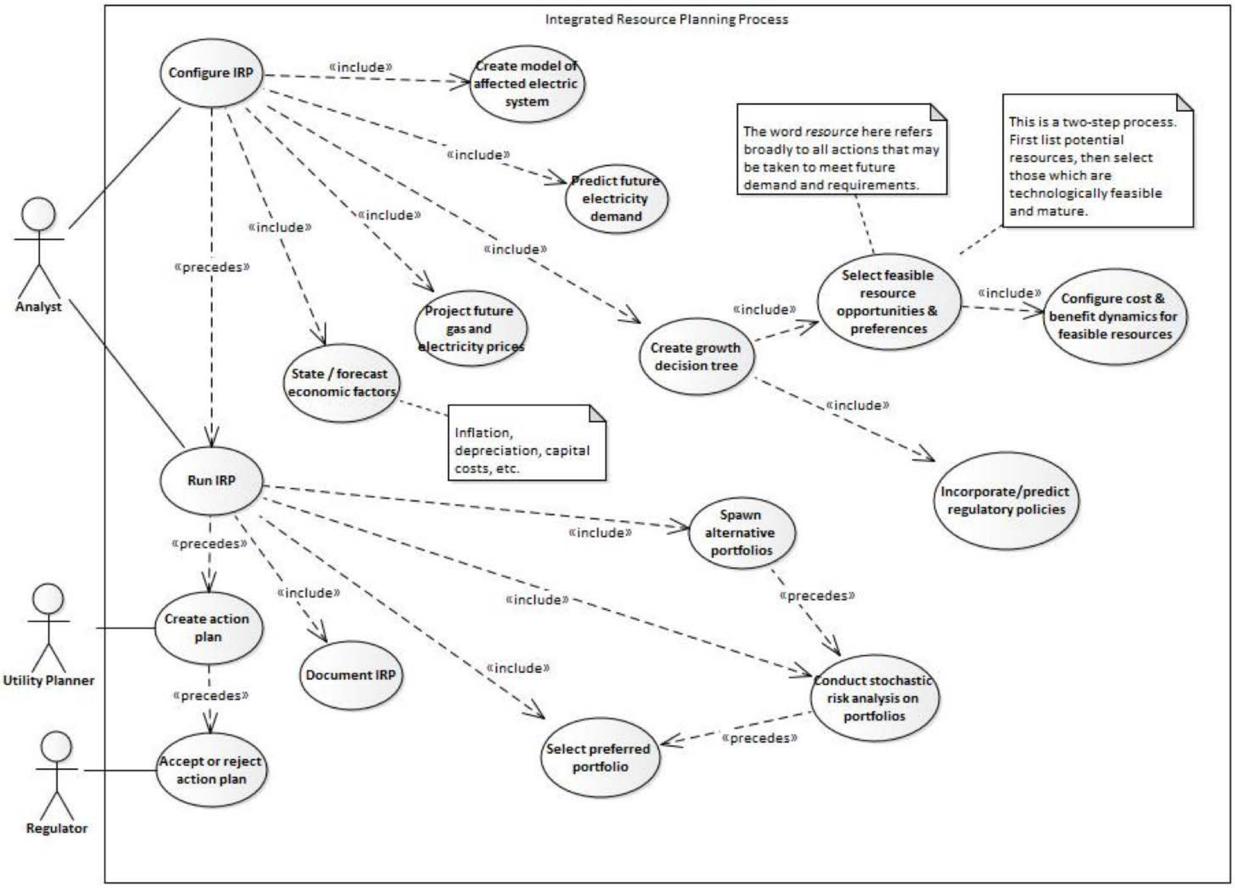

Figure 3.1. Integrated Resource Plan Use Case Diagram

Once the Analyst has configured the IRP, the IRP analysis is performed and the Utility Planner (those responsible for defining the specific, actionable plan) puts together a short-term action plan based on the IRP, the Regulator (typically the public utility or public service commission for the jurisdiction in question) reviews the resulting integrated resource plan and, typically, gives it a stamp of approval of sorts. The regulator's stamp generally takes the form of an "acknowledgement," as opposed to an explicit approval. [3]

[3] At a high level, a current regulatory commission cannot "commit" a future commission in ways that strip that future commission of their responsibility to act in ways that protect ratepayers while at the same time providing incentives to the utility to perform their role responsibly. So the stamp of approval is something like an "acknowledge the IRP." Generally, including a resource in an IRP does not guarantee cost recovery, but development of a resource that was not included in a previous IRP does more generally lead to a denial of cost recovery.

Figure 3.1 includes stochastic risk analysis on portfolios. When the analysts set up and run the IRP, the analysts assess possible variability in the major inputs. Some inputs might include significant uncertainty, for example future natural gas prices. For variables like fuel prices and wholesale market prices which are known to be volatile, analysts will typically construct at a minimum three cases – a main or reference case, a high case, and a low case, plus a probability of each case materializing. The cost of most forms of supply- and demand-side resources are fairly well-defined and understood, but the costs of other such as solar generation or energy storage have been declining rapidly in recent years, so analysts might construct scenarios to assess the impact of future price changes and the probability of such alternative scenarios occurring. Most of these input assessments take place in other bubbles on the diagram, such as the "state / forecast economic factors" or the "configure cost & benefit dynamics" bubbles.

The main or reference scenario would typically incorporate regulatory policies that currently embodied in legislation or regulations which are on the books, and that have been or are expected to be implemented. However, if proposed new rules or legislation appear likely to be enacted, the Analysts will construct scenarios bracketing what they believe to be the realistic future regulations including the timing of the implementation. When the Analysts conduct stochastic risk analysis they assess the impacts on key metrics of running the models assuming the alternative cases occur, or by running the models and allowing the models to run many scenarios, selecting input cases based on the probability of occurrence and ultimately averaging the results in some way. When the Analysts select the preferred portfolio, the preferred portfolio tends to be the portfolio with the lowest risk-adjusted impact on future revenue requirements or on future rates.

Because the IRP process has the goal of ensuring a utility possesses sufficient resources to meet loads, the end result of the analysis is a long-term plan for resource acquisition. In short, the IRP is a guideline for engaging a specific set of resources, both existing and future. This guide includes all types of resources, demand-side resources, supply-side resources that are considered renewable, supply-side resources that are not considered renewable either because they burn a fossil-fuel or because the RPS legislation or regulations specifically excluded them (e.g., in the Pacific Northwest, many thousands of megawatts of hydroelectric generation are not considered renewable for RPS purposes), resources purchased in wholesale power markets, and other distributed resources. Thus IRP can also be pictured as a use case diagram summarizing the process of acquiring resources. Figure 3.2 depicts such a diagram.

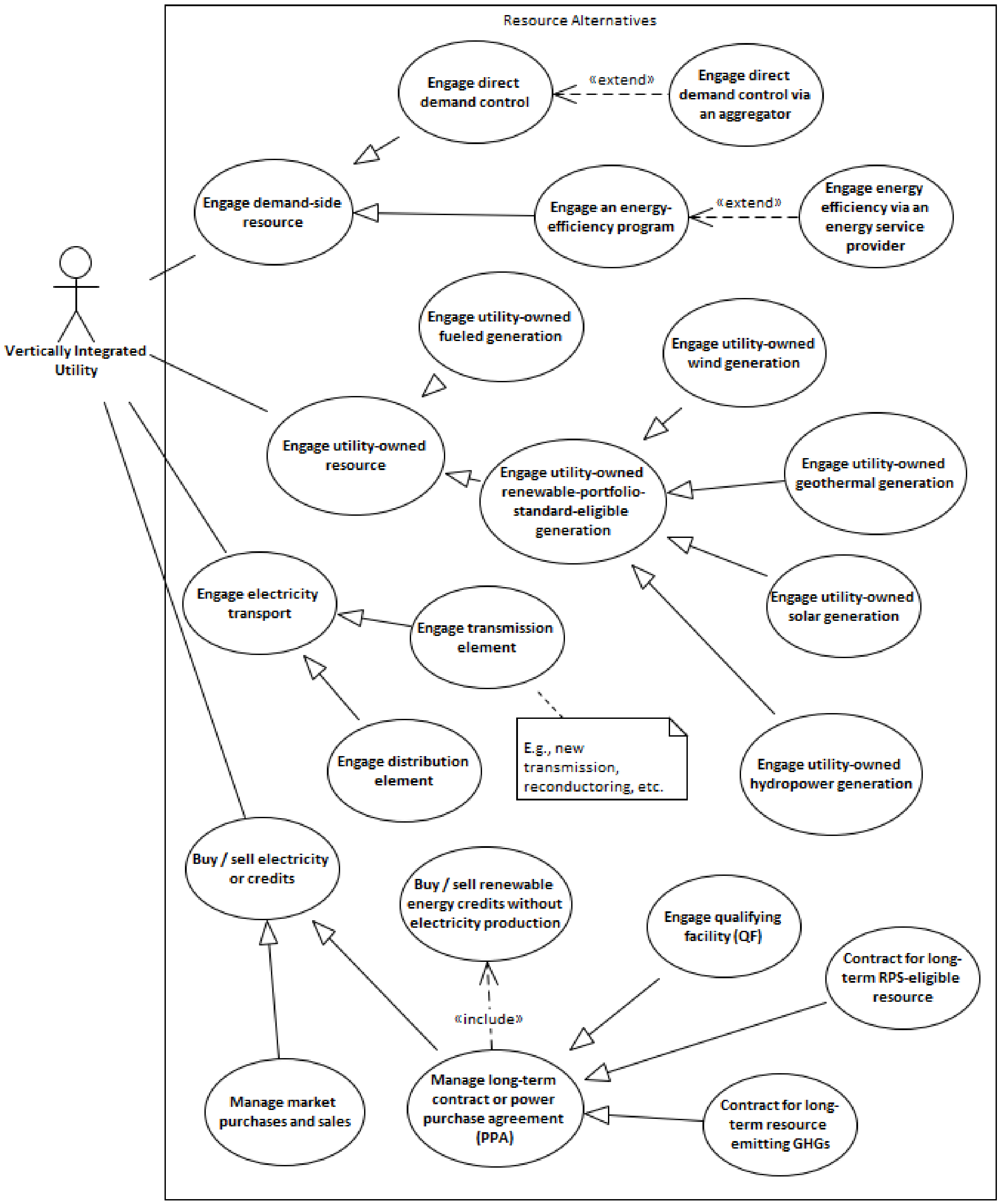

Figure 3.2. Utility Resource Procurement Use Case Diagram

As shown in Figure 3.2, in any given year the utility may engage one or all of the various types of resource acquisition activities. With any given procurement activity, the utility may/will need to engage the delivery service function (distribution and/or transmission). There are some activities that could be within the utility such as the DSM function or that could involve extensions of the utility program by way of the use of an independent third-party to operate the DSM programs on behalf of the utility. As noted in the overview of IRP, the process explicitly includes work to ensure the utility meets RPS requirements, so one of the “values” that the utility buys and/or sells when buying or selling electricity is the acquisition or sale of Renewable Energy Credits (RECs).

3.4 IRP Class Diagrams

All the actors in the systems being modeled in Business Value Diagrams are classes. It’s important to understand the classes being modeled by first examining the class diagram.

Class diagrams are a diagram type that provides two specific pieces of information that are helpful in understanding the system being modeled:

1. The diagram defines the types of actors that are being modeled in the system; these are called “classes”.
2. The diagram shows some of the relationships between actors, specifically relationships of specialization and aggregation.

   “Specialization” refers to a class that is highly similar to another class in many ways but differs in some other ways. For example, we could choose to define a “Power Plant” class that has a sub-class that is more specialized: “Coal-Fired Power Plant”.

   “Aggregation” refers to classes that are parts of a larger class. For example, we could choose to define a class as a “Vertically Integrated Utility” which is composed of classes including “Accounting Department” and “Power Marketing Department”.

   There are other relationships that exist between actors and other diagram types that emphasize those relationships (including those modeled in the Business Value Diagram). Specialization and aggregation focus on the relationships between the nature of the classes rather than the purpose, role, or performance of the classes. This is important to support that Business Value Diagrams where a single actor shown in the diagram may be a stand-in for several types of similar actors (specialization) or a stand-in for a larger number of actors that make up the whole (aggregation). These two types of relationships allow for a more compact representation of complex systems in other portions of the diagrams.

Figure 3.3 is the class diagram that was constructed to show the actors that should be considered when modeling the activity of the utility for the purposes of an IRP analysis. Most of the actors are self-explanatory but there are a few items of particular note.

The “New Resource Supply Company” has a number of sub-class actors, one for each of the types of power plants that could be constructed; this is an example of the specialization relationship. This relationship was defined in this manner to show that the procurement of a new power plant largely considers the resource in a generic manner with consideration of only a limited number of differences based on the underlying source of energy. That is, the similarities in the plants for the purposes of IRP are more similar than different and are somewhat interchangeable. In a similar manner, the “Power Plant Upgrade or Decommissioning Company” has a number of specialized sub-class actors that could be hired to maintain or improve existing power plants to ensure the continuity of that resource.

The “Vertically Integrated Utility” class actor makes use of the aggregation relationship to show the two actors that are modeled as part of the VIU. Though this is a very small subset of the actors that could have been included in the model, it was determined that this limited subset was all that was likely needed for modeling the value flows associated in IRP. The value flows associated with the actors not shown are either not significant or would not be expected to change as a result of a procurement decision made based on the IRP analysis.

The numbering associated with the origination and termination point of the arrows connecting these classes is used to indicate the potential number of actors associated with these relationships, called “ordinality”. In this case, the “1..*” is used to show one or more “VIU-Owned Power Plant Staff” are a part of “1” utility. Similarly, the “0..*” indicates zero or more “VIU-Owned Power Plants” are a part of “1” utility (indicating it is possible for viable IRP scenarios to result in a utility owning no power plants).

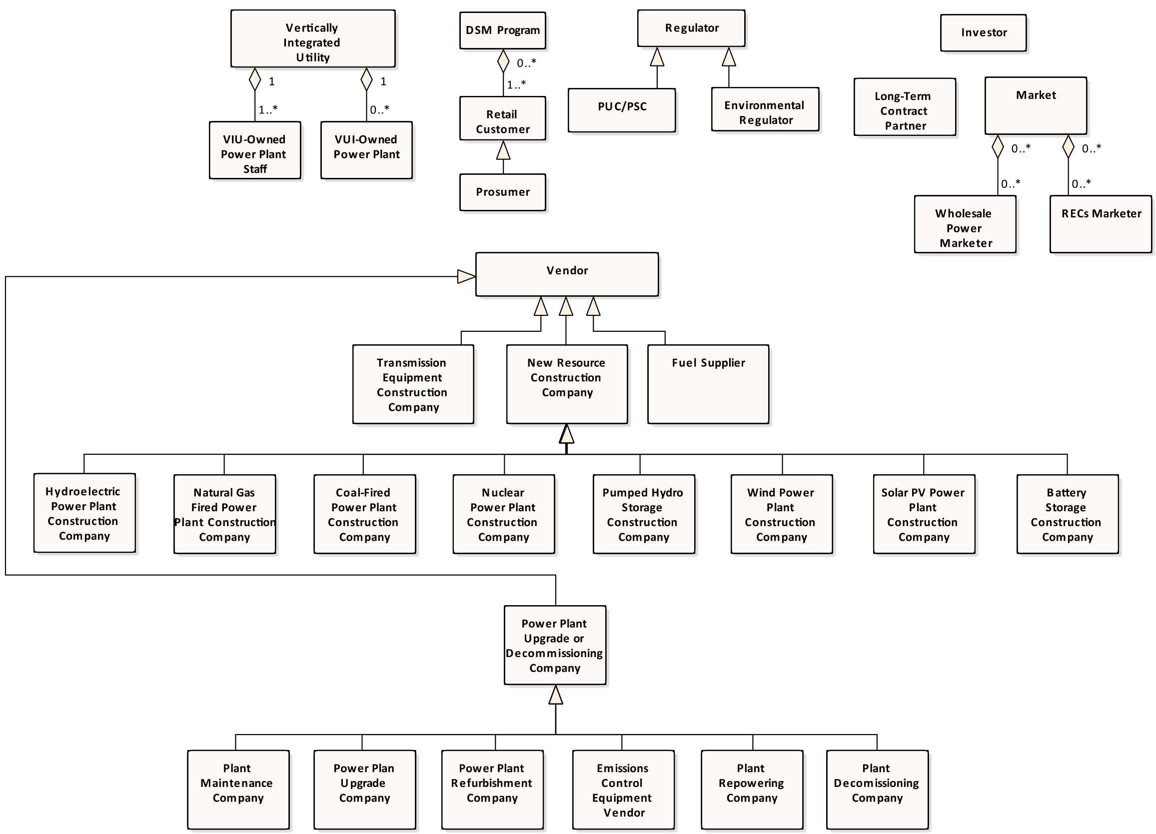

Figure 3.3. Class diagram of actors for modeling utility for IRP purposes

3.5 IRP Business Value Model

The business value model developed for this task is used to define actors and their interactions as related to the operation of the power system under nominal conditions. This is consistent with the goals of IRP to support the procurement of the appropriate resources to meet the system load at some future date. This system could be composed of a variety of assets, and the business value diagram constructed as a part of this work is intended to represent these as competing alternative options. [4]

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[4] For those who are unfamiliar with business value diagrams, it is important to make the distinction between the actions required to perform the IRP analyses and the transactions that are modeled by the IRP. The business value

diagram does not model the process by which an IRP is formed; that is, the process a utility goes through to reach an acknowledged IRP involving meetings with stakeholders, utility commission hearings, etc.

The business value diagram is used to evaluate the costs of various resource development and/or procurement options needed to support normal system operation over the time of the analysis period. This is the model of the power system that could be used by those doing IRP, not a model of the IRP stakeholder process itself.

Relatedly, the business value diagram is a model and as such contains simplifications. Specifically, it eliminates many aspects of normal operations that would not be significantly changed based on which assets were procured to meet future load. For example, though there is a value exchanged between the electrical utility and its janitorial staff (salary and benefits in exchange for cleaning services), such values are not expected to be any different whether the electrical utility decides to invest heavily in renewable generation or demand response programs. Such eliminations increase the clarity of the model and allow it to focus on the more significant expenses by reducing the number of details shown.

Figure 3.4 shows the high-level overview of the value exchanges associated with the IRP development process.

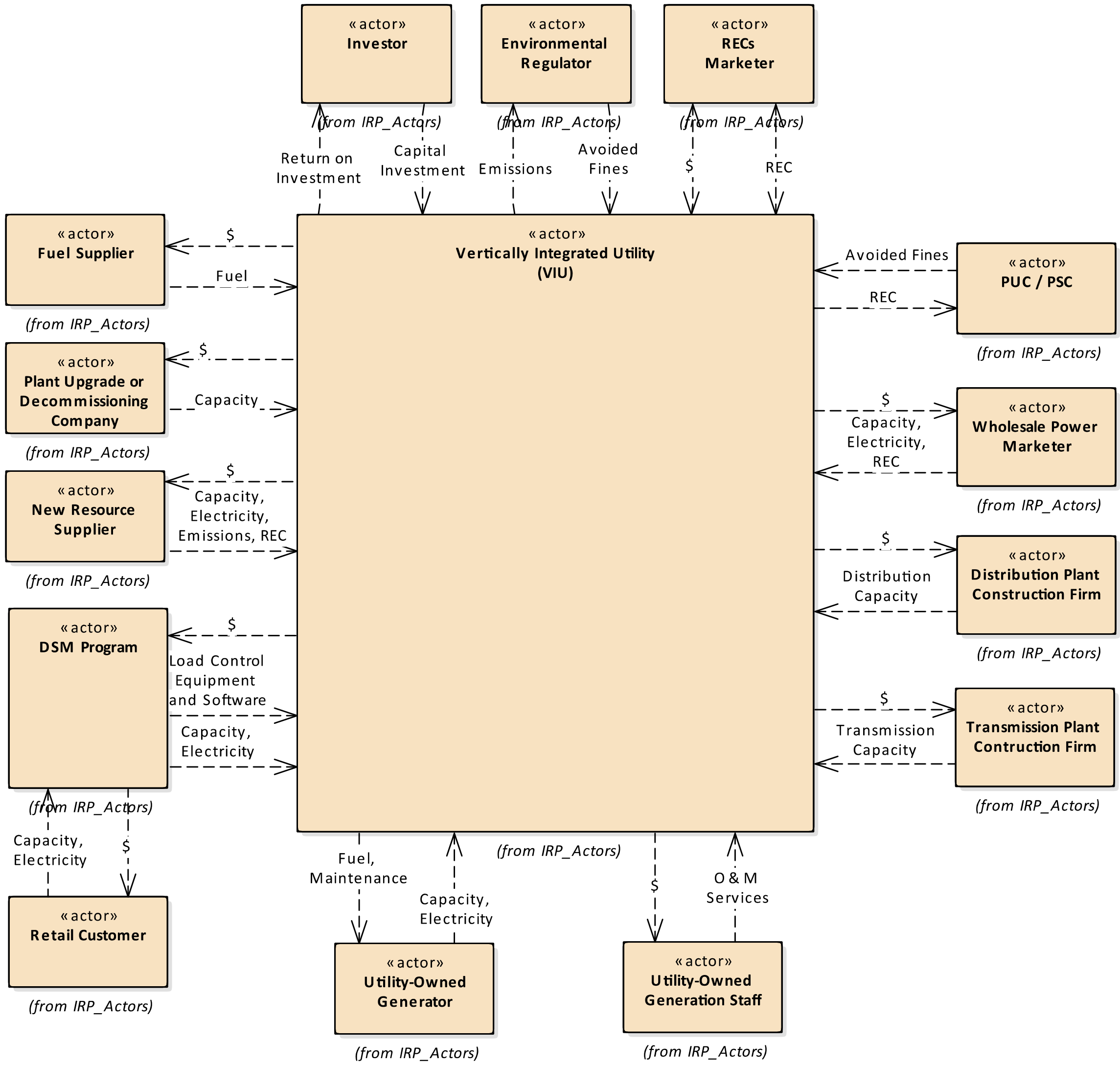

Figure 3.4. High-level business value diagram for IRP analysis

Figure 3.4 depicts the value exchanges embodied in an IRP. The value diagram is general in the sense that the transactions captured on the diagram might occur in every year of the integrated resource planning period, or in only 1 year. The central actor in this diagram is the vertically integrated utility. The smaller boxes surrounding the VIU are other actors with which the utility has transactions. Connecting the VIU and the other actors are arrows showing what is traded between the parties. Frequently, money ($) will be sent by one actor to the other actor, in exchange for something, like electricity or RECs. Note the direction of flow can go either way over the IRP period. A utility does not deliberately plan to acquire excess generation because typically the regulator would look askance upon such plans but given the utility must purchase generating assets in blocks there may be years when the utility has excess generation or REC, and the IRP models could predict a sale in some future year to benefit from the excess.

If one could add up the flows depicted over the planning period, the result would be either a metric of interest or a measurement required by a metric of interest. The word "electricity" is used to denote kilowatt-hours (kWh) and kilowatts (kW), plus the ancillary services needed to provide acceptable levels of service, i.e., the frequency and voltage response services needed to avoid sags and surges and the regulating reserves needed to keep the system in balance. Customers tend to think they are buying kWh from a utility but generally buy a more complex mix of services. For this value diagram we use the word electricity when the product transaction is not clearly capacity or energy.

The following is a general discussion of the features of this diagram and what the features and the diagram show us.

- **Retail Customers:** Ultimately, an IRP is a tool for meeting the electricity needs of customers. Thus, the value diagram shows the utility sending customers electricity and in return the customers send the utility payments (dollars). For utilities with IRP models that calculate costs literally all the way to estimated future rates, aggregating the dollars over the IRP period would embody a key metric. Aggregating the components of electricity is also a key metric insofar as it comprises the IRP's ultimate target.
- **Investors:** Investors provide the VIU with capital needed for investments, in return for a return on the investors' capital. Investors were included because their capital is a necessary ingredient in the VIU's ability to fund construction projects, and because the predominate paradigm for calculating the return to investors depends on the magnitude of the VIU's rate base. The latter consideration has historically led some stakeholders to believe VIU decision-making at least tacitly favors decision leading to a larger rate base, i.e., in favor of supply-side resources, at the expense of DSM options said stakeholders believe to be less expensive (Reid 1990).
- **Environmental Regulators:** Environmental regulators are increasingly an important actor in the IRP process. Though they are not necessarily a part of the PUC or PSC, all generation resources that will be constructed will eventually have to be approved by environmental regulations and thus their involvement in the long-term plans to construct such assets is expected. Examining the current IRP of any major VIU, it is clear that a significant number of decisions regard question like:
  - Should we add pollution controls to this plant?
  - Should we re-fuel this plant?
  - Can we avoid adding pollution control to this plant by agreeing to prematurely retire a different plant?

  As noted in the assumptions Section 3.2, it is assumed utilities will strive to meet environmental requirements. The transactions between the VIU and the Environmental Regulator are avoided fines or penalties and "emissions." This latter commodity does not mean the VIU delivers emissions to the regulator. Rather, the VIU demonstrates to the regulator they have met the requirements placed upon the utility by the regulator to avoid emissions.
- **RECs Marketers:** REC marketers are the final actor shown on the value diagram. In today's markets, there are entities that have RECs they can sell to other actors, like our VIU. RECs are an attribute of energy and can be unbundled from the energy – meaning, the VIU can buy either the energy along with the RECs, or they can purchase the energy only or the RECs only. While we assume the VIU will attempt to meet RPS requirements, there are reasonable situations where the VIU might fall a bit short of their REC requirement. REC Marketers provide the VIU with an option to purchase RECs to enable the utility to meet their REC requirement. Note transaction can go both ways. If the VIU finds themselves long on RECs in any given year due to the lumpiness of renewable resource acquisitions, the IRP models could choose to sell RECs to benefit from the surplus.
- **Fuel Suppliers:** Utilities all purchase fuel for their facilities and this interaction captures that large portion of the marginal costs utilities have.

- **PUC / PSC:** In the value diagram the public utility or public service commission sets and administers or enforces the RPS regulations, so the utility sends the PUC/PSC the RECs required to show compliance with the RPS, and in turn, the PUC/PSC pronounces they met the RPS requirements and do not assess any fines or penalties. Again, the sum of the RECs over the IRP period would be a key metric.
- **Wholesale power marketers:** The utility can enter into transactions of any duration with actors in the wholesale power market, with transactions ranging from sub-hourly to multiple years (often the case when a utility purchases some or all of the output of a generating facility for multiple years as one might see when a utility acquires wind energy or solar energy). Such purchases may assist the utility in meeting RPS requirements, so one of the values exchanged might be RECs.
- **Transmission and Distribution plant construction firms:** To the extent a VIU identifies a very specific generating plant to build or a specific purchase from the wholesale market for which transmission or distribution capacity is needed, the VIU would look to construction firms to build the facility. In this case the flows are dollars from the utility and transmission and/or distribution capacity to the utility.
- **New resource suppliers:** One class of actors is the new resource suppliers. Each utility has a list of the types of generating resources they consider building whether it be wind, solar, geothermal or other renewable resources or whether it be fueled by coal, nuclear, gas or oil.
    - When a utility thinks in terms of fueled resources like a gas turbine, the utility tends to think in terms of purchasing capacity, with $ going to the suppliers, and with the utility “accruing” emissions.
    - Renewable resources might be characterized more as energy resources given many have poor capacity factors. In this case $ goes to the supplier and energy/some capacity flows to the VIU along with RECS.
- **DSM programs:** DSM programs include energy efficiency (EE) which is generally considered an energy measure, load management which is a capacity measure, price response and informational programs. Load management is dispatchable and can compete against peaking resources such as battery energy storage and combustion turbines, while the other DSM efforts tend to be treated in IRP as reductions to the load that must be met.
- **Plant Upgrade or Decommissioning Companies:** Within IRP this is primarily a capacity measure as the VIU examines the load and the other supply- and demand-side resources available to it and examines other constraints such as emissions limits and selects the least cost approach to meeting capacity and other requirements. Several transactions can potentially take place between the VIU and several different actors. Generally the VIU is sending dollars to the other actors in exchange for actions potential changes in the capacity available to the utility, decreases in the emissions during operations of the existing plant, extend the life of a plant, or change the fuel used in the plant. Thus, in exchange for dollars, the utility receives an increase in capacity.
- **Utility Owned Generation and Generation Staff:** Because the plant upgrade and decommissioning affects utility-owned resources, the IRP should be capturing potential changes in staffing and other internal costs. Staff and VIU-owned generation costs are variable over the IRP period. If the IRP determines a particular generating resource should be decommissioned, the staff associated with that plant would likely be laid off, so staff costs have a direct and not inconsiderable cost impact though likely small compared to the other costs of a generating facility.

To conclude, the IRP is a tool for assessing the electricity requirements of retail customers and other constraints such as RPS and emissions requirements, for identifying the least cost method of meeting the various requirements. If the commodities transacted between the VIU and the other actors on the value diagram can be summed, across years, the result would either be the metrics captured by the VIU or would be with some manipulations such as discounting the dollar value streams.

3.6 Key IRP Metrics

Given the broad scope of the IRP analysis, the volumes of data produced are large and complex. Though there may be many metrics that are of importance to the utility (projected changes in staffing requirements, retirement or construction of specific plants, impacts of specific regulatory requirements, expected return to investors, etc.), there are generally a few key metrics that are the essential outcomes of the analysis as it pertains to the PUC:

- **Net present value of revenue requirement[5] (NPVRR):** The value is essentially the total cost over the analysis timeframe to execute on a given portfolio of resources. That total cost will largely, if not entirely, be borne by the customers of the utility resulting in a strong preference for portfolios with low costs. There are other metrics of interest (discussed below) but cost is first and foremost.

  For utilities performing more advanced analysis, the NPVRR for a given portfolio is subjected to a risk analysis considering such factors as changes in fuel prices, regulations, and market behavior. The result of this analysis is a risk-adjusted NPVRR which is then compared across portfolios.

  For a given resource portfolio, the dollar-denominated value streams flowing out of the central VIU block in Figure 3.4 are the modeled costs of the utility. The more detailed analysis of each portfolio would produce a time series of specific numerical value associated with these value flows. Making analysis decisions of the time-value of money (interest rates) for the analysis period would allow these value streams to be normalized to a net present value and produce the final NPVRR. Under the assumption that the utility stays financially solvent for the duration of the analysis, this value should be exactly balanced by the dollar value streams flowing into the utility, primarily if not entirely found in the payments being made by customers.

  A relatively common variant of the NPVRR metric is an assessment of future rates, and finding the portfolio that minimizes future rate increases.

- **Emissions:** In many cases, there are regulatory constraints on emissions from power plants within a given utilities jurisdiction. Typically portfolios are assembled and modified such that they will meet these constraints, verified through the analysis process. In some jurisdictions there may be public relations and customer satisfaction value that would incentivize a utility to go further than required by regulation increasing the appeal of a given portfolio even if the risk-adjusted NPVRR is higher than another with higher emissions.

[5] Revenue requirement refers to the amount of money a utility must recover through rates to pay all of the utility's costs plus a reasonable return to stockholders. While there are other intervening steps, in essence, retail rates are the revenue requirement divided by the number of kilowatts and kilowatt-hours a utility is expected to bill.

The emissions consequence of a given resource portfolio can be simply found by summing all the emissions-denominated arrows flowing into the central VIU utility block. The specific values would be found through other analysis techniques (likely time-series simulation) that define the specific emissions output of all resources engaged by the utility to meet the demand of the customers. Though in reality the emissions do not literally flow to the utility (but rather to society as a whole) it is modeling and accounting convenience to show them accumulating at the utility, creating an easily tabulated emissions footprint for a given portfolio.

- **Renewable Portfolio Standards (RPS):** In many jurisdictions there are regulatory requirements to produce a certain percentage of energy from renewable energy sources. As in the case of emissions, this is often treated in the IRP process as a constraint that all portfolios must meet. Similarly, there may be less tangible benefits of exceeding the renewable energy requirements that may make some portfolios more attractive than others.

  RPS compliance is typically met through the generation or purchase of RECs which are then transferred to a compliance regulator who retires these RECs (to ensure they cannot be double-spent by other utilities or the same utility at a future date). There are thus two metrics associated with RECs: those that have been acquired by the utility (shown as the RECs-denominated arrows flowing into the utility) and those transferred to the regulator for compliance purposes. It is generally expected that these two values would be roughly equal for a given period of time but this is not necessarily the case. A utility may generate more RECs than it needs and is unable to sell them or a utility may not be able to transfer enough RECs to the regulator and in turn receive a fine.

  As in the other metrics a separate analysis technique would be used to define the specific timing and quantity of the RECs acquired to ensure compliance.

3.7 IRP Value Exchange Process – The Activity Diagrams

The business value diagram presented in Figure 3.4 clearly shows the options a utility can pursue to meet expected loads with an appropriate level of resources over the years covered by the IRP. A utility can obtain capacity and/or energy either through wholesale market purchases, self-generation, demand-side management, or from DERs. With existing generating facilities, in any given year, the utility can choose to:

- maintain facilities and continue operating each existing plant as-is;
- upgrade existing facilities (i.e., make changes that expand or reduce the capacity of existing generation);
- refurbish old plants to extend their capacity or their expected lifetime;
- add emission control equipment to meet emission standards to avoid shutting plants down;
- repower plants, or renovate the fuel handling systems to burn a different fuel;
- perform work to extend the life of plants, including top-to-bottom inspections and working with relevant regulators for necessary permits and approvals; or
- retire and decommission existing facilities.

As shown in **Error! Reference source not found.**, these decisions involve transactions with other actors, with which the utility enters into transactions, sending money/payments to external parties in exchange for the services listed above.

The utility has other options. They could:

- build new generation of varying types, as shown in **Error! Reference source not found.**, by engaging actors who specialize in the construction of various forms of energy supply/generation facilities
- enter into contracts of varying length with Wholesale Power Market actors
- add new demand-side management (DSM) programs, either load control programs in which the utility purchases equipment and software from vendors and offer incentive payments to customers for the right to control loads, or energy efficiency programs in which the utility provides incentives to customers who purchase more efficient equipment, or contracting with an independent third party implementer who acquires demand reductions/energy savings on behalf of the utility.

The business value diagram shows the range of available options, although in any given year under consideration the utility is apt to only select a subset of the available options. All options are shown because the diagram is intended to be applicable to any or all years of the IRP analysis period – as opposed to needing individual, customized diagrams for each year of the analysis.

The previous diagrams model the IRP at a high level. To capture and illuminate the numerous transactions related to resources, it is helpful to drill down into aspects of the models. Following is more detailed descriptions of the transactions previously summarized at high levels. The descriptions discuss the main categories of resources in more detail.

3.7.1 Existing Fueled Resources

Figure 3.2 depicted the acquisition of resources. One portion of this diagram indicated the IRP analyst would "engage utility-owned fueled generation." A high-level picture of what "engage utility-owned fueled generation" means is contained in the activity diagram shown in Figure 3.5. The figure drills into the activity showing additional actors and the transactions between the utility and the actors. As noted in **Error! Reference source not found.**, the utility has multiple options with an existing resource. Because the IRP attempts to balance electricity and RPS and environmental requirements, the IRP assesses several options for existing resources. The utility can continue to simply maintain and operate existing resource as shown in the Vertically-Integrated Utility swim lane (column) in Figure 3.5. The utility could make significant changes to one or all existing resources such as decommissioning, re-powering, upgrading or making changes that reduce the plant's capacity, improving emissions control, or performing other work extending the life of the plant.

These actions are shown as involving Vendors as well as Regulatory approvals and Customers being asked to pay for the changes, all of which are shown in their own swim lanes. The actions selected based on the IRP analysis may have impacts on the utility's need to borrow money and or the utility's return payed to stockholders, as shown in the Investor swim lane. The actions selected by the VIU may be driven in part by the need to comply with emissions regulations as indicated by the presence of the Emissions Regulator in the Regulator swim lane and the note that the utility emits regulated emissions in the Utility swim lane. The utility either continues to buy fuel or not, impacting the fuel vendor in the Vendor swim lane. Finally, the utility continues to sell retail electricity to (Retail) Customers.

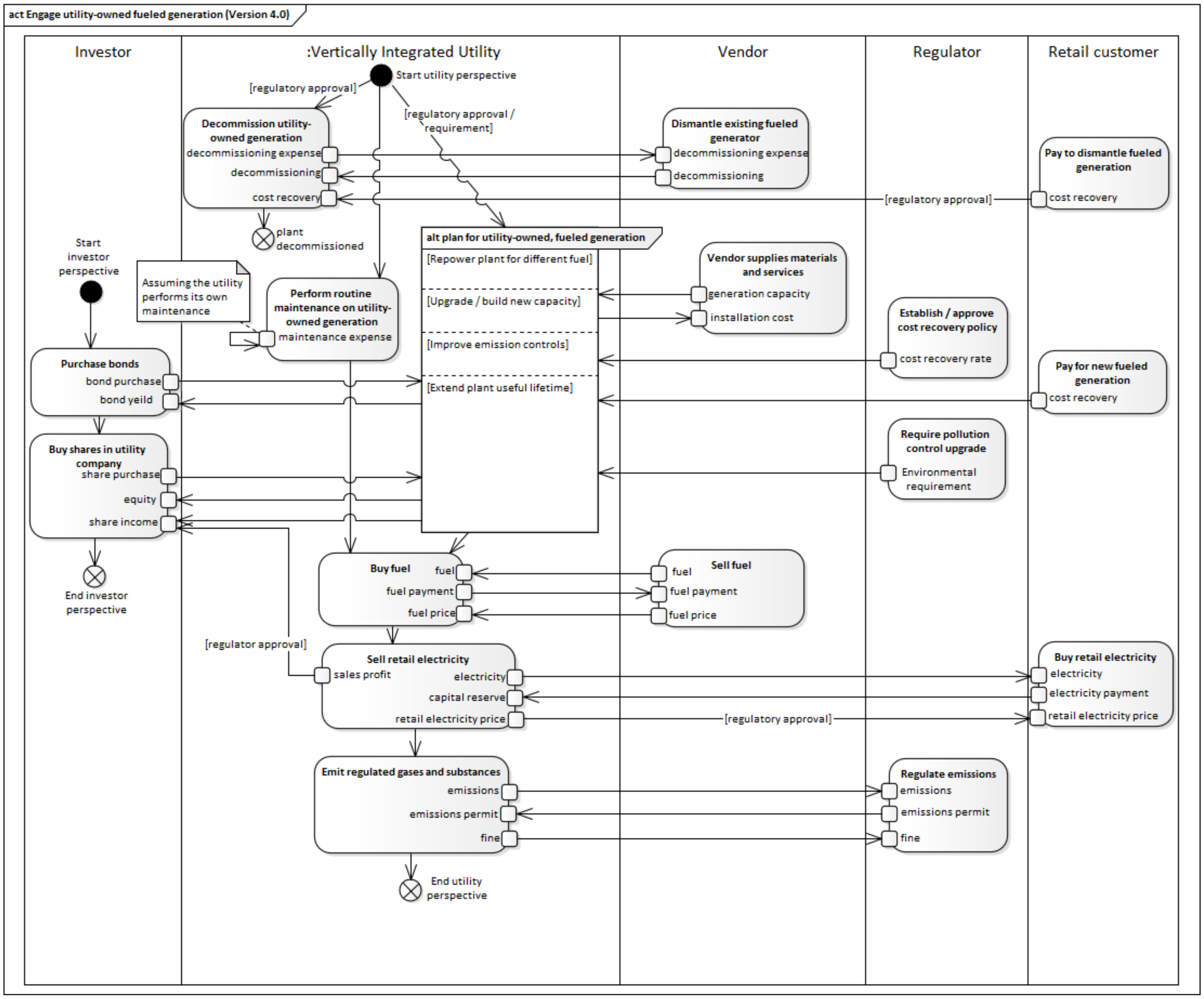

Figure 3.5. Engage Utility-Owned Generation Activity Diagram

3.7.2 Utility-Owned Renewable Resources

Because much effort in IRPs is dedicated to meeting RPS requirements and/or emissions control requirements, renewable resources differ from fueled resources in a key way – the renewable resources are not constrained by the same emissions regulations as fueled resources and the renewable resource generate a different value stream, namely RECs. This is shown in Figure 3.6. As with fueled resources, the changes in renewable resources can impact Investors, so Investors have their own swim lane. Construction or purchase of resources involves equipment Vendors and the approval of such involves Regulators. Additionally, the Regulator swim lane includes the entity which certifies RECs.

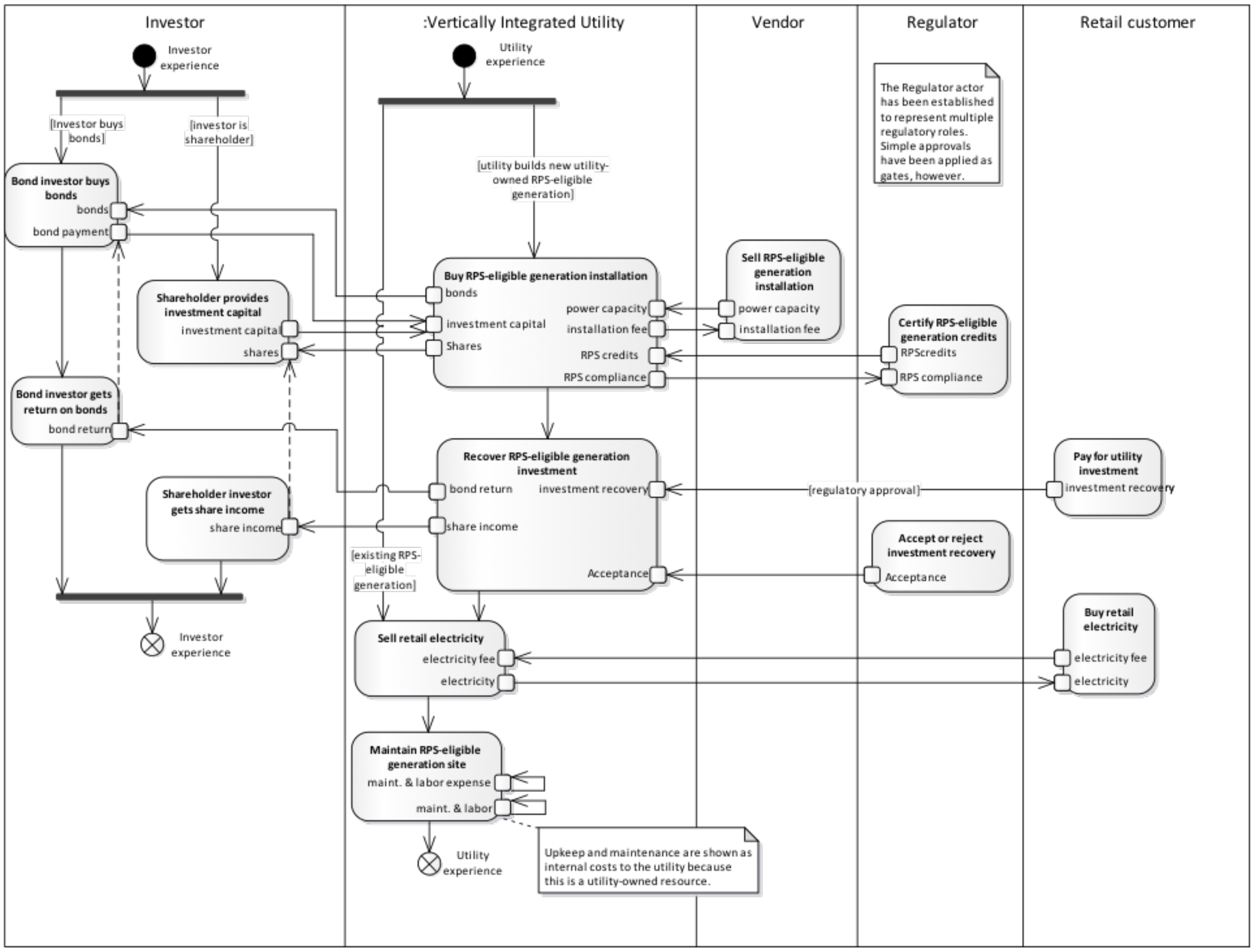

Figure 3.6. Engage Utility-Owned Renewable Resources Activity Diagram

3.7.3 Wholesale Market Sales or Purchases

As noted in the high-level diagrams shown in Figure 3.1, Figure 3.2, and Figure 3.4, the IRP considers wholesale market purchases as separate classes of resources, and models such with their own sets of inputs and makes selections based on the relative economics as well as how well market purchases help the utility meet other constraints such as RPS requirements. This is shown in Figure 3.7. Note in the Utility and the Contract Partner swim lanes there are several values exchanges of interest – how much future capacity is available, the price, when the capacity is available, whether RECs are available and whether it impacts the utility's position with respect to emissions. It should be noted that IRPs are not vehicles for utilities to justify constructing resources for purposes of selling power into wholesale markets. In the IRP, the sale in wholesale markets is a byproduct that might positively or negatively impact a potential decision. However, to the extent the IRP modeling system results in excess capacity in any given year it would also model potential revenues from sale of such excess capacity. Also shown in Figure 3.7 is the possibility of simply going into the REC market and buying or selling RECs, either purchasing because with the utility's own generation and purchases of renewable energy the utility is short of its requirements, or selling because the utility finds it has more RECs than it needs. Again though, the IRP is not a vehicle for developing resources to sell RECs – such sale would generally be an incidental byproduct. The investors do not earn a rate of return on the investment of physical assets in transactions involving market sales and purchases, but they may provide capital reserves and if approved by the regulator, be allowed to retain a share of profits made from market transactions.

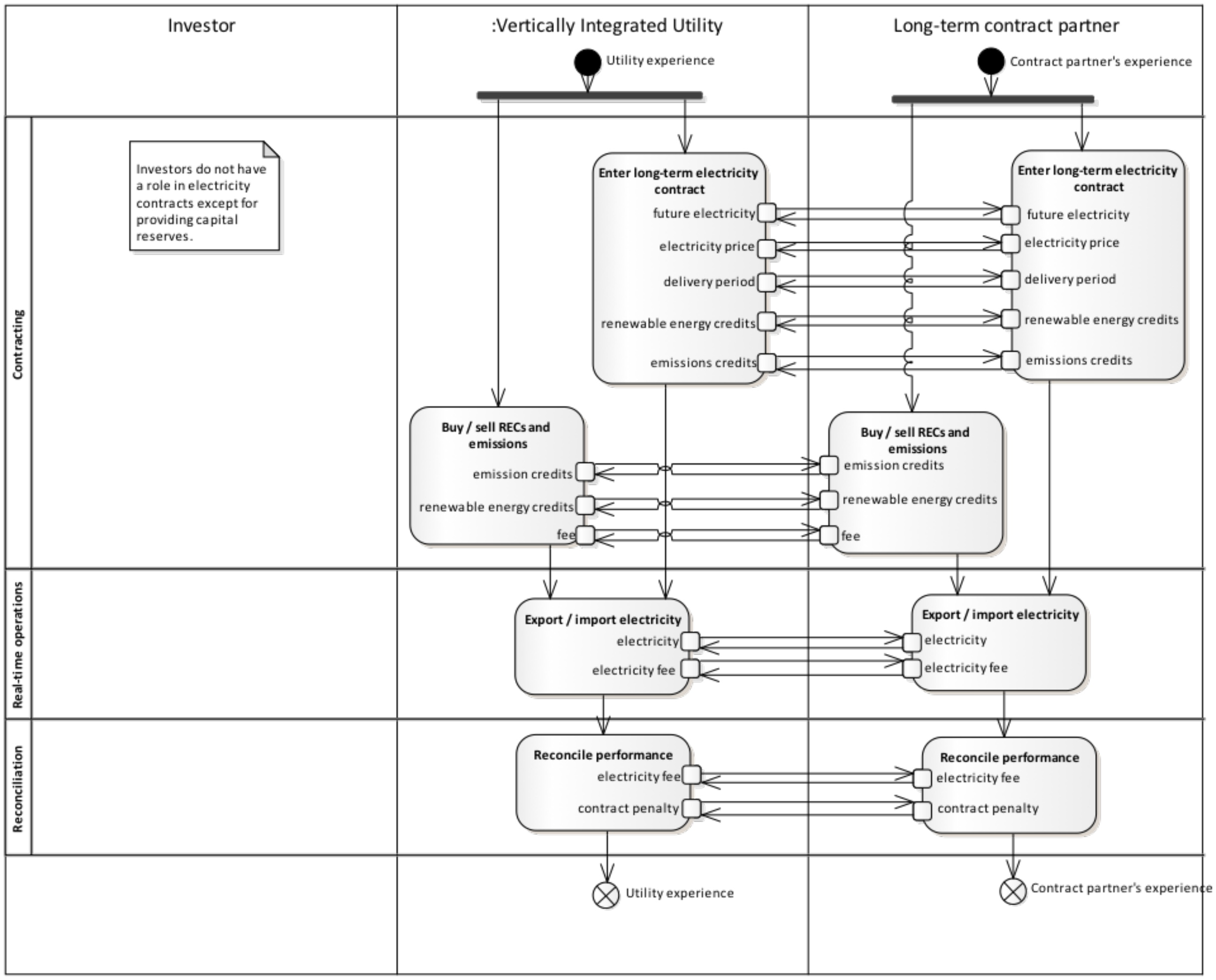

Figure 3.7. Purchase and/or Sale of Power in Wholesale Market Activity Diagram

Figure 3.7 considers buying power via long-term contracts, such as buying wind power for a 10-year period. Utilities can also plug short-term holes in their future resource portfolios by buying power for short periods, for example, buying 100 MWs to cover short on-peak windows in future years when the economics of constructing a new resource are not justified. This is depicted in Figure 3.8. While it is possible such purchases might also have REC or emissions implications, the IRP analysis process does also select some short-term purchases based simply on economics.

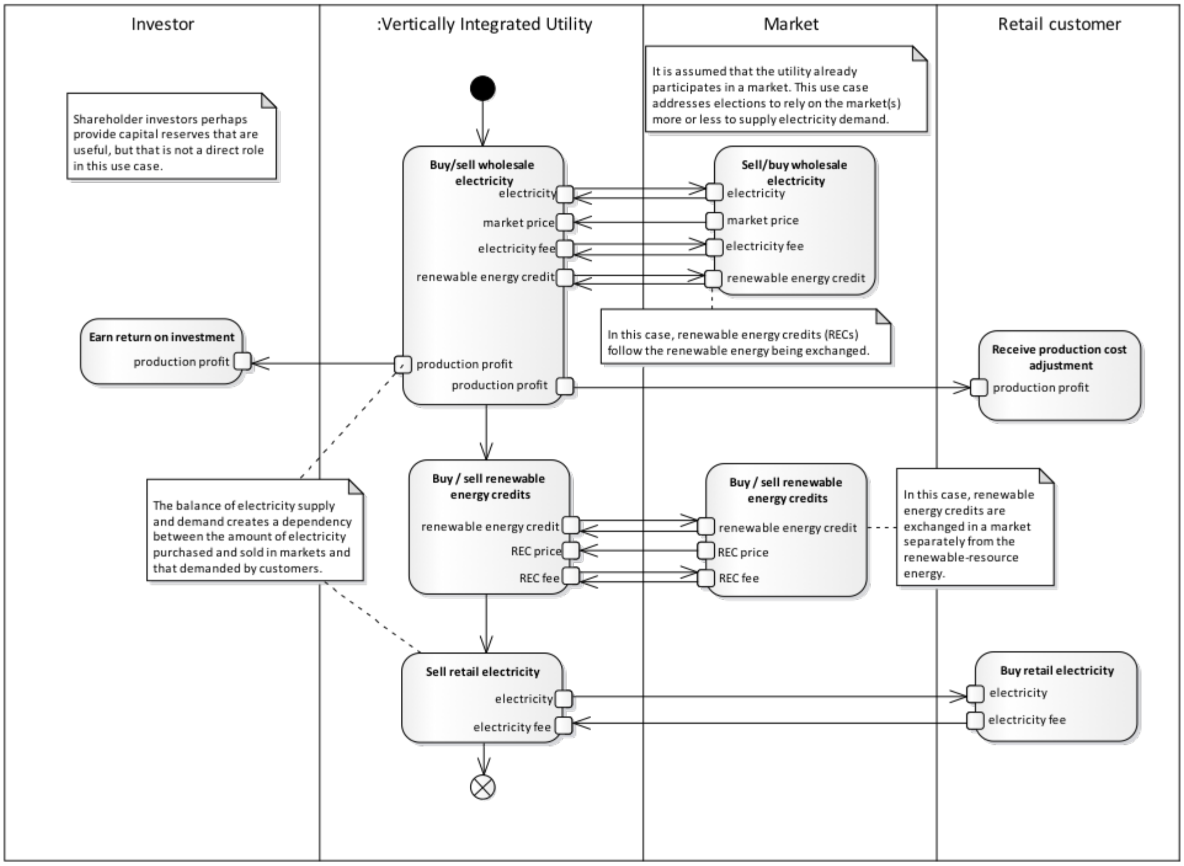

Figure 3.8. Managing Market Purchases Activity Diagram

Because the wholesale market purchase are scalable and might-or-might not be purchased in large blocks, the utility might not need to raise significant funds through investor markets. Also, unlike supply-side resources, wholesale market purchases typically do not add to the rate base upon which return to stockholders is predicated. Thus, though the Investor swim lane is included in Figure 3.7 and Figure 3.8, the Investors do not have a major role in this resource category.

3.7.4 Demand-Side Resources

The demand-side resources are the final, major category of resources. Figure 3.9 depicts the "engage demand-side resource" activity that was included in Figure 3.2. Because demand-side resources can be either instigated by the utility in the form of DSM programs or instigated by aggregators, the diagram shows two starting points in the Utility and the DER[6] Aggregator swim lanes. In both cases, there is an assumption that something is being installed at the utility customer's premises – equipment that either reduces demand or equipment that can be used to control demand such as a load-controller placed on a water heater tank. Thus, regardless of the instigator of the program, it will involve vendors who sell and install equipment. Both programs include the utility customer. Because the DER resource is scalable and

[6] DER is generally defined to include both the traditional utility DSM programs, plus distributed generation (DG) resources such as customer-owned solar generation which is connected to the distribution network. Currently, DG is largely outside of utility control. Some utilities are currently treating DG as a distribution resource and including it as a non-wires alternative in distribution plans. In IRPs utilities are presently treating DG as a reduction to load forecasts and not treating DG as a resource the utility actively tries to acquire to meet electricity requirements.

is not by its nature purchased in large and expensive blocks, the utility can typically fund this without needing to raise significant funds through investor markets – and, unlike supply-side resources, DER typically does not add to the rate base upon which return to stockholders is predicated. Thus, though the Investor swim lane is included, the Investors do not have a major role in this resource category. Utilities, and therefore investors, do not earn a return on investment in demand side management, as they do with infrastructure investments that increase the rate base.

Performance-based regulation can affect the return to investors if a given DSM program does not meet its expected performance. This is a mechanism used by regulators to ensure that estimates of DSM performance set in the IRP are reasonable and adhered to rather than a plan that is routinely ignored. Performance-based regulation allows utility commissions to penalize investors for under-performing DSM. This penalty is not considered during the IRP process as it is assumed the VIU is not cynical and will set reasonable DSM performance expectations rather than overestimate the performance to avoid some other costly measure and pay the penalty down the road.

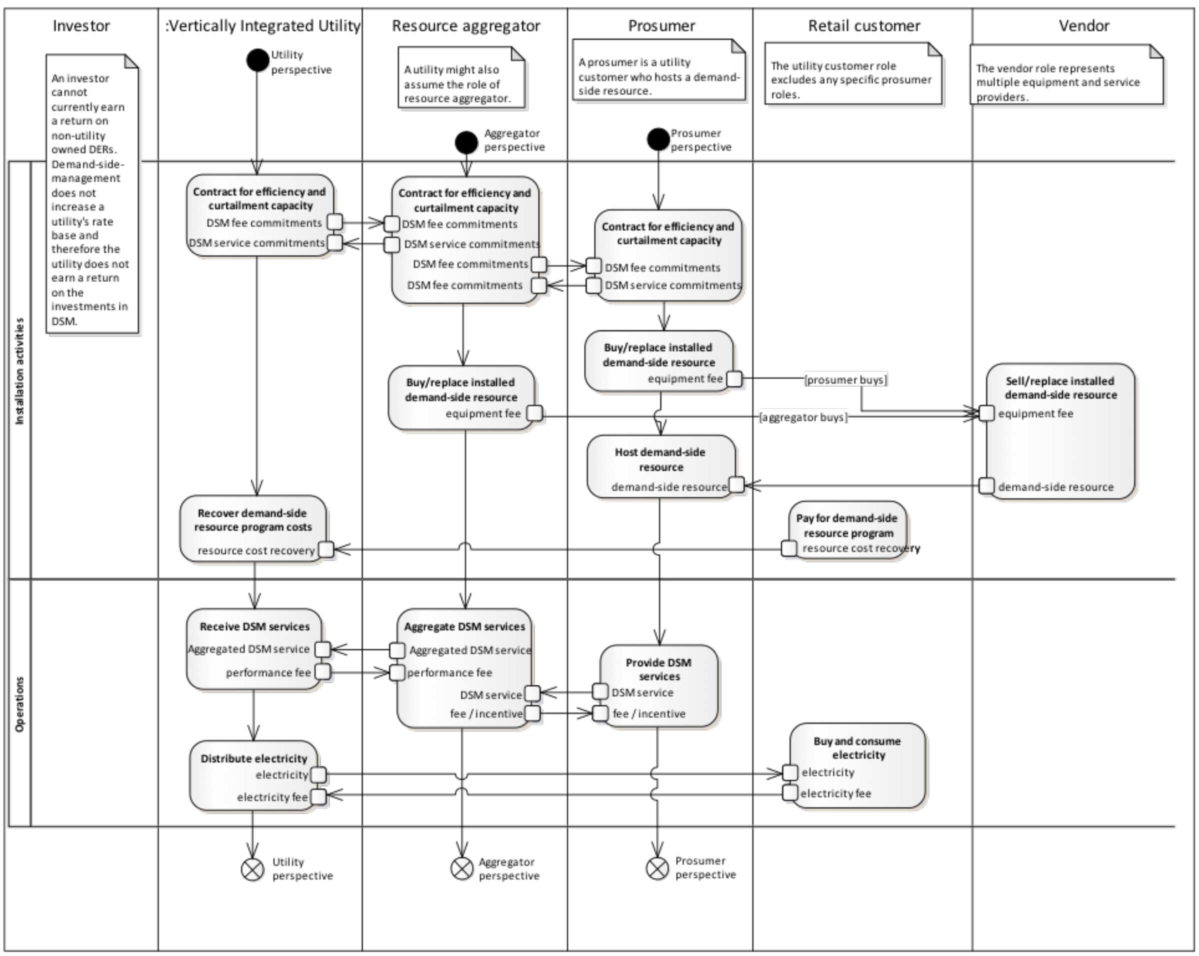

Figure 3.9. Demand-Side Resource Activity Diagram

3.7.4.1 Emissions and RECs as Constraints and Value Exchanges

Some constraints placed on utilities can have major impacts on the IRP results; for example, emissions limitations, such as mercury, sulfur, and nitrogen oxides, particulates or carbon. In each year of the analysis, the utility models numerous alternative power system configurations ("portfolios") to determine which portfolio meets the load requirements, as well as other constraints such as maintaining emissions below expected limits (which would be placed on the utility externally by the EPA and regional and state air quality regulators). Thus, constraints influence the portfolios insofar as the portfolio must meet the constraints. Note that with existing generation there is an option to meet the emissions constraint by installing pollution control equipment – which implies a value exchange between a utility and a vendor of such products. However, this is not the same as saying the level of emissions itself offers value exchange possibilities, where a commodity (i.e., emissions) is exchanged for payments.[7]

In the case of emissions, utilities face the possibility of fines and/or other penalties for failing to comply with emissions directives or limits. There are also opportunities for utilities to negotiate compliance strategies with regulatory agencies, such as not installing pollution control equipment in the year required, but instead agreeing to retire a power plant earlier than its depreciable life. Such negotiations would not typically be included in the IRP technical analysis but could be considered a viable business strategy developed upon reviewing the results of the analysis. In the business value diagram, emissions are shown accruing to a utility and we show the utility "delivering" the emissions to air quality regulators in exchange for avoided fines. This same thinking applies, in part, to RPS compliance. While it is assumed utilities choose to comply with emissions and RPS requirements, as shown on the business value diagram, non-compliance at the cost of fines and other penalties is an option. While it is a constraint like emissions, RPS compliance does offer specific value exchange possibilities. The RPS is a constraint insofar as the utility has specific targets in specific years (e.g., 25 percent renewable energy in the resource mix by 2025) and we assume a sincere effort to meet the targets. One aspect of renewable energy, renewable energy credits (RECs), has specific value exchange possibilities because there is an active market for RECs.

The REC market exists due to the fact that the "renewable attributes" of electrical energy from a renewable energy resource can be separated from the energy and marketed independently. When the REC is purchased separately from the energy produced by a renewable generator, the REC is called an unbundled REC. When the renewable attributes or RECs stay bundled to the energy produced, the REC is referred to as a bundled REC. Throughout the United States, RECs are a commodity that are actively traded in RECs markets across utilities. In some states, utilities can procure bundled or unbundled RECs for RPS compliance. Thus, REC marketers appear as actors on the value diagram with transactions between the utility and REC marketers. Note, one convention of the business value diagram is that transactions can go both directions. If purchasing 100 RECs is a positive flow of RECs, selling 100 RECs could be conceived as a negative flow from the utility's perspective. Thus, the REC market can be seen as both a source and a sink for RECs.

3.7.4.2 Investors

One actor mentioned but less thoroughly discussed to this point is the investors in for-profit utilities. Various resource alternatives have different impacts to utility investors, which can impact resource decision making from a business perspective. For relatively small or incremental investments such as purchasing a small amount of wind energy from a power marketer, or building a DSM program in annual increments, a utility might be able to fund the purchase from retained or current earnings. For a large new

[7] In the case of some pollutants in some regions of the country, there are markets for buying and selling "credits" for the right to emit certain pollutants. However, these pollutants have, from outward appearances, been minimized to such an extent that recent utility IRPs tend to not focus on the pollutants with active markets. Rather, IRPs in recent years focused on carbon dioxide and regional haze regulations. Carbon dioxide is not served by active markets. Regional haze compliance tends to be highly site specific and the possibility of allowance trading is limited by the requirement of improving visibility within a very specific geographic region.

baseload generating station, the utility would need to sell bonds or issue stock. Additionally, some of the options like wholesale market purchase do not result in changes to what is known as the “rate base,” or a measure of accumulated plant-in-service less depreciation.[8] The level of payment to stockholders for their investments in the company is based in part on rate base, so the selection of new generation which adds to rate base has different business implications to investors than other resource choices that either add far less to the rate base (i.e. load control programs) or that do not add at all to the rate base (i.e. wholesale purchases). Thus, investors are included in the value model as a source of investment money and because the utility is required to repay bonds and to pay some level of return to shareholders. Within the current utility business model and regulatory paradigm, there are certain resource investments that increase rate base and therefore result in higher returns to investors than others, and this can be a factor in resource decision making.

4.0 Conclusion

As was originally speculated and now demonstrated in Section 3.0, the value modeling technique developed for transactive system studies is more broadly applicable and can be used when performing IRPs. The types of the diagrams typically used for transactive system studies fit well into modeling the systems and processes under consideration when performing IRP and provide additional insight that may or may not be clear when directly evaluating IRP of a given utility.

For example, as discussed in Sections 2.0 and 3.7.4.2, the role of investors in IRPs is both integral (as the introduction of a profit incentive motivated the need for IRPs) and tacit. Profits to investors are not a key metric included in IRPs but the reality of any investor-owned utility (which most VIUs are) requires a return on investment for the VIU to continue as a going concern. The value model developed here explicitly shows the Investor actor and makes it clear what they provide the VIU and receive in return. If using this value model, any IRP analysis could include return-on-investment as a metric and report it as a part of the IRP as it is an explicit value exchange and any analysis implemented from this model would necessarily have to include that interaction.

More generally, as discussed in Section 3.6, the business value diagram in Section 3.5 supports the calculation of the key IRP metrics (NPVRR, emissions, RECs) in a very direct and simple manner. All value exchanges shown in Figure 3.4 have a time-series of numeric values behind then that would be required to be generated as a part of the IRP analysis proper. This time series supports a large number of metrics that could be of interest to a utility (e.g. revenue required over the next five years, generation capacity as a function of time, volume of excess RECs that could be sold as a function of time, etc.) and well-summarizes the detailed analysis that may or may not be obvious to PUC/PSC commissioners and their staff when examining the IRP report from the VIU.

Similarly, the sequence of events modeled in the IRP analysis as shown in Figure 3.5, Figure 3.6, Figure 3.7, Figure 3.8, and Figure 3.9 offer a simplified view of the VIU operations to execute their core business activities. Such detail, even in such a summarized fashion, is typically not included in IRP filings and may or may not be clear to PSC/PUC commissioners and staff. These details are important in understanding how the VIU runs its business and provides insight into process of procuring the necessary resources to meet load.

[8] This definition is simplified insofar as rate base also includes plant and equipment held in stores for repair and replacement needs.

In summary, the value model developed here of the IRP process using the techniques developed for transactive systems has been useful in providing increased clarity and definition to how IRPs are performed and the decisions faced by utilities when planning the means by which the future load will be met.

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