Analysis of the management of uncertainty in long-term planning for electric utilities

by

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Abstract

Electric utilities engaging in integrated resource planning face a variety of uncertainties which complicate the development of robust plans. These uncertainties occur in variables such as demand growth, energy price, green house gas regulations, and water inflows for hydroelectric-dominated utilities, just to name a few. This study examines the current planning methods in use among (largely North American) utilities with a particular focus on the features of each method that manage or mitigate uncertainty. The two most common planning methods (portfolio-based and scenario-based planning) are analysed and their advantages, disadvantages, potential alterations, and circumstances of best application are evaluated. These findings are then applied to the case of BC Hydro, one of the largest electric utilities in Canada, with recommendations for changes to their current planning process.

Preface

This dissertation is work carried out by the author Laura J. Irvine under the supervision of Prof. Ziad Shawwash. Chapter 1 and Chapter 2 were prepared as an internal report for BC Hydro's Energy Planning and Generation Resource Management groups. A version of Chapter 1 is also intended for presentation at the 2017 HydroVision Conference in Denver, USA. Chapter 3 is prepared as a manuscript for submission to a journal in energy planning and policy. As Chapter 3 draws together all the findings and implications from Chapters 1 and 2, some sections in Chapter 3 are modifications of previous sections.

Prof. Shawwash contributed to editing of all chapters and preparation of Chapter 3 as a potential journal paper. Sanjaya de Zoysa from BC Hydro's Energy Planning group provided guidance on utility selection, BC Hydro's IRP process, and manuscript editing for Chapter 1. Wun Kin Cheng and Doug Robinson from BC Hydro's Generation Resource Management group explained the structure of the HYSIM and GOM models and their use in the IRP, which was incorporated in Chapter 2.

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List of Abbreviations

Arizona Public Service (APS)
Demand-side management (DSM)
Duke Energy Indiana (DEI)
Energy efficiency (EE)
Greenhouse gas (GHG)
Los Angeles Department of Water and Power (LADWP)
Northwest Power and Conservation Council (NWPCC)
NorthWestern Energy (NWE)
Pacific Gas & Electric (PG&E)
Public Service Company of Colorado (PSCC)
San Diego Gas & Electric (SDG&E)
Southern California Edison (SCE)
Tacoma Public Utility / Tacoma Power (TPU)
Tennessee Valley Authority (TVA)

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Introduction

Background

Electricity planning, as any planning, involves making decisions with uncertain information about the future. Projections based on historical data are not completely accurate representations of the future and can fail to capture the emergence of new factors. Because of the essential nature of electricity services, utilities have to provide reliable service to their customers in spite of their own uncertainty.

Reliability of supply comes from accurate capacity planning on the part of utilities. This requires knowledge of future energy demand as well as planning to ensure supply keeps pace with this load. To match capacity expansion to load growth, utilities are required to make judgements about the future values of variables that affect load growth and resource acquisition. These variables are factors like population growth and economic growth (which go into determining the load), and energy price, GHG taxes and prices, uptake of demand-side management, and regulation on particular fuel sources, all of which affect which potential resources are best for meeting new load. Utilities handle this uncertainty in their planning in a variety of ways. This thesis will investigate current practices for managing uncertainty in electric utility planning, examine how the planning steps mitigate or manage uncertainty, and develop a formal framework for evaluating the robustness of a capacity expansion plan in the face of uncertainty. This framework will then be applied to the specific case of BC Hydro. The goals for this research are: fuller understanding of current uncertainty management in practice; identification of both good practice and shortfalls in current planning; and assessment of BC Hydro's planning method, with the additional aim of improving their current uncertainty management in the IRP.

Structure of thesis

This thesis is structured in the following manner. Chapter 1 presents a literature review of the current state of IRP practice in North America, examining the published IRPs of fifteen utilities. Each utility's practice is explained, any unique features are highlighted, and uncertainty management in each method is identified. Chapter 2, building on the literature review, analyses in depth BC Hydro's IRP process, looking at their optimisation models, simulation models, and sensitivity analysis, and recommending changes to the process to better consider the effect of uncertainty on the portfolio development. Chapter 3 then presents conclusions on the content of both preceding chapters, identifying the underlying drivers for choice of planning method, the explicit consideration of uncertainty in each step of planning, the pros and cons of each method for uncertainty management, and a brief summary of recommendations for BC Hydro.

Chapter 1

Literature review on current uncertainty management in the energy industry

This section reviews the current practice of uncertainty management among a number of North American utilities and was originally prepared as a report for BC Hydro. The references cited in this section have been included in the thesis bibliography.

1.1 Introduction

BC Hydro carries out an integrated resource plan (IRP) for their long term capacity expansion every five years. This research was commissioned by BC Hydro to identify the most common practices in utility resource planning, in particular management of uncertainty, with a view to providing BC Hydro with more methods for managing their uncertainty in their planning process. While other jurisdictions do practice IRP (South Africa[1], Queensland [2], among others) Canada and particularly the USA had the most examples of IRP. As a result, the report largely focuses on utilities in these countries.

Across North America different jurisdictions have different requirements for IRP planning, with some states requiring it and some having abolished it. The individual utilities reviewed were chosen for a variety of reasons. Public Service Company of Colorado, PacifiCorp, and Arizona Public Service were chosen for review based on a paper on best practice published by the Regulatory Assistance Project [3]. Tennessee Valley Authority was reviewed as an example of a public utility that is wholly owned by the United States government. Tacoma Public Utility and Idaho Power are smaller utilities that have somewhat different planning processes. Finally, the Californian utilities PG&E, SCE, and LADWP were included to give a perspective on planning process in a partially deregulated energy market.

The terminology used throughout to describe planning techniques is derived from Hirst and Schweitzer[4]. Scenario analysis is identified as being a technique in which alternative versions of the future are developed, combinations of resources that perform best in each future are selected by a model, and the best options are combined into a complete plan. Portfolio analysis is defined as planning in which multiple future resource portfolios are developed, each corresponding to a specific company objective, and then modelled, analysed, and assessed against potential futures. A general overview of an IRP process is illustrated in Figure 1.1.

1.2 Utilities reviewed

The following sections summarise the main features of the planning processes of the reviewed utilities.

1.2.1 Arizona Public Service

Arizona Public Service (APS) serves 1.2 million customers in the state of Arizona [5]. As of 2014, the company had 8,124 MW of generating capacity heavily based on fossil fuels and nuclear power (Table 1.1). APS files their

Figure 1.1: A general IRP process

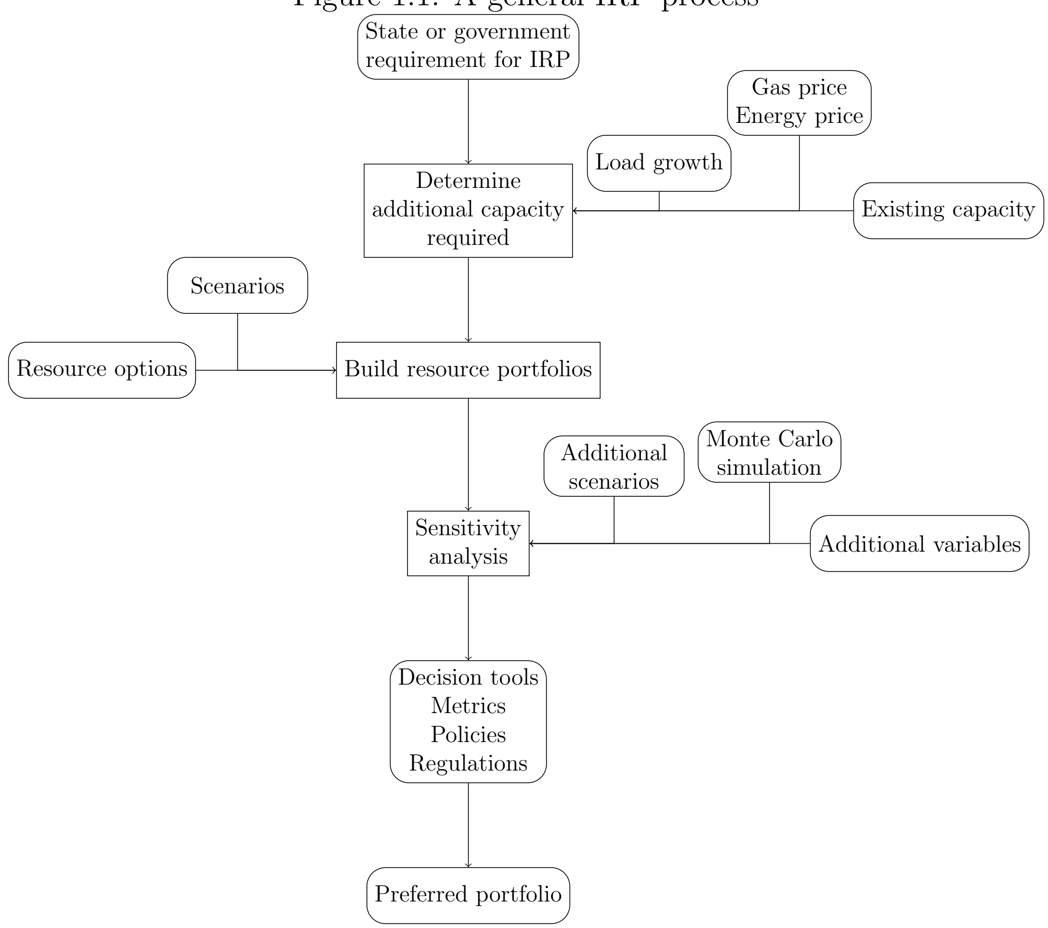


Table 1.1: APS's energy mix

Energy source	**Percentage**
Nuclear	28
Coal	38
Natural gas	24
Renewables	5
EE/DSM	5
Total	100

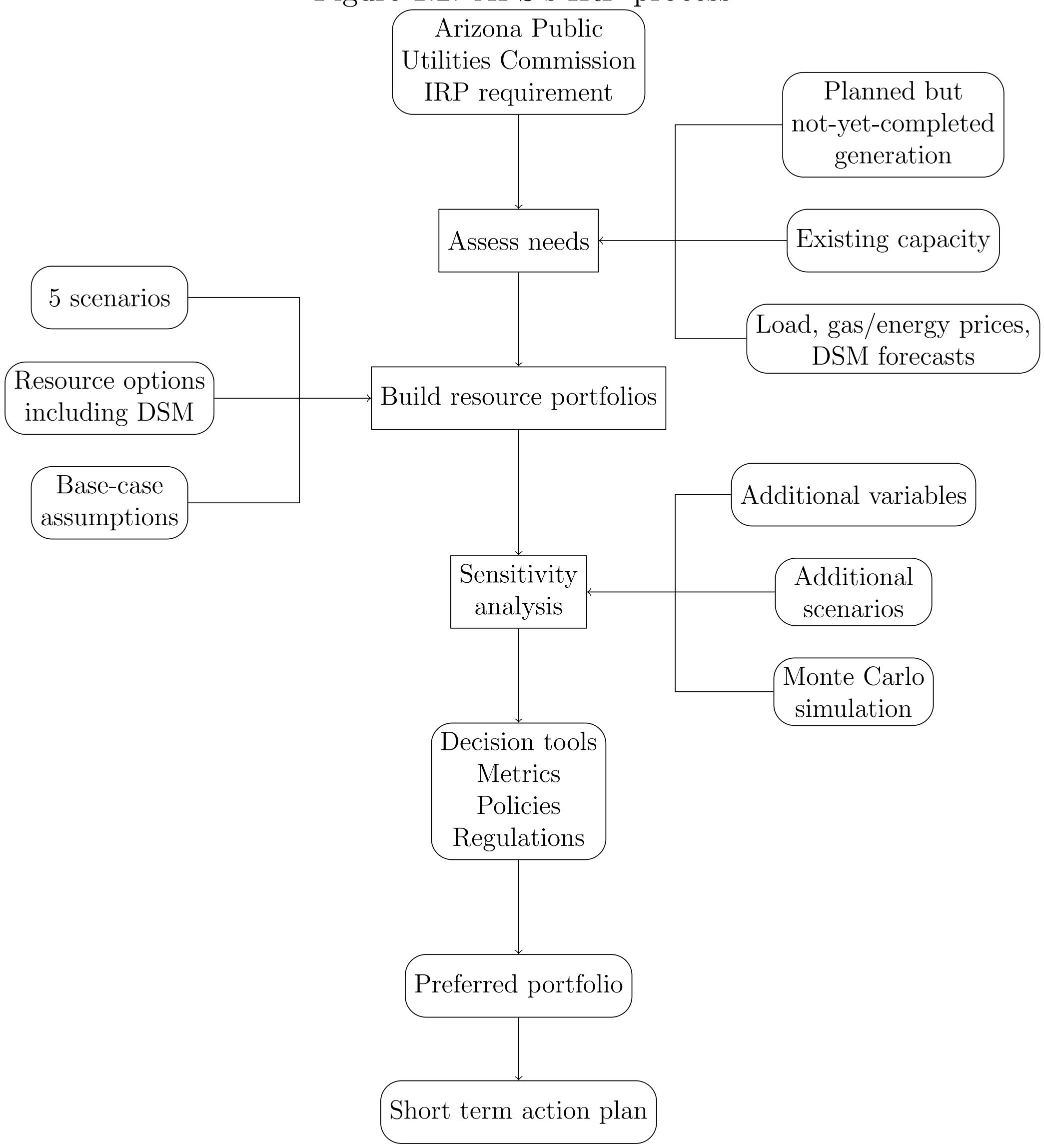
EE: Energy efficiency
DSM: Demand side management

IRP, which has a planning horizon of 15 years, with the Arizona Corporation Commission every two years. The IRP also contains the 2014-2018 Action Plan, which outlines the steps to be taken in the near-term to implement the IRP recommendations over the full planning period. Figure 1.2 outlines APS's IRP process.

APS forecasts peak load growth of 3 percent per year over the fifteen year planning horizon. Weather, population growth, economic trends, and energy consumption patterns are used to create the load forecast using PROVIEW, a module of the Strategist model from Ventyx/ABB. The IRP considers three planning forecasts: a current path with 3 percent average growth per year; a low load growth path with 1.6 percent average growth per year; and a high load growth scenario with growth of 4.2 percent per year.

APS handles most of its uncertainty by using multiple scenarios and a range of deterministic forecasts. Examples include scenarios such as retiring coal or setting a higher renewable energy goal than currently required by law. The utility uses a total of six scenarios in their optimisation model, PROVIEW, to develop their resource portfolios. The variables that change between scenarios include load forecast, gas prices, power prices, inflation, renewable energy regulations, carbon prices, and tax incentives for technology. The process is traditional deterministic optimisation; PROVIEW is

Figure 1.2: APS's IRP process



given the existing resources and a scenario with various constraints and allowed to compile an optimal portfolio from a range of potential resources with the aim of minimising cost. Once the six portfolios have been created, the four lowest-cost ones are chosen for sensitivity analysis with the PROMOD model. APS used several key metrics to select a preferred portfolio from those generated by the model. These were fuel diversity, portfolio cost (both net present value of revenue requirements as well as average system generation cost), cumulative capital expenditures, natural gas used, carbon dioxide emissions, and water use. These criteria were useful for evaluating portfolio performance in terms of concerns other than cost. The eventual preferred portfolio can be chosen based on its stable performance across all the metrics, even if it does not outperform every other portfolio on every metric.

1.2.2 Idaho Power

Idaho Power operates in the states of Idaho and Oregon [6]. The investor-owned utility services about 515,000 customers in southern Idaho and eastern Oregon and a generation capacity of 3,954 MW [7] (see Table 1.2 for a breakdown of sources). The utility is required to file an IRP with both the Oregon Public Utility Commission and the Idaho Public Utility Commission every two years.

Idaho Power has historically been a summer-peaking utility due to demand from irrigation pumps and air conditioning. Their load forecast for the IRP is developed by Moodys Analytics, Inc., and is based on regional and national economic activity, population forecasts, employment levels, and historical energy consumption patterns. Because of uncertainty, Idaho Power uses an expected case (median) forecast as well as two additional forecasts (70th percentile and 90th percentile) to capture most of the expected variability.

Idaho Power does not use an optimisation model to construct resource

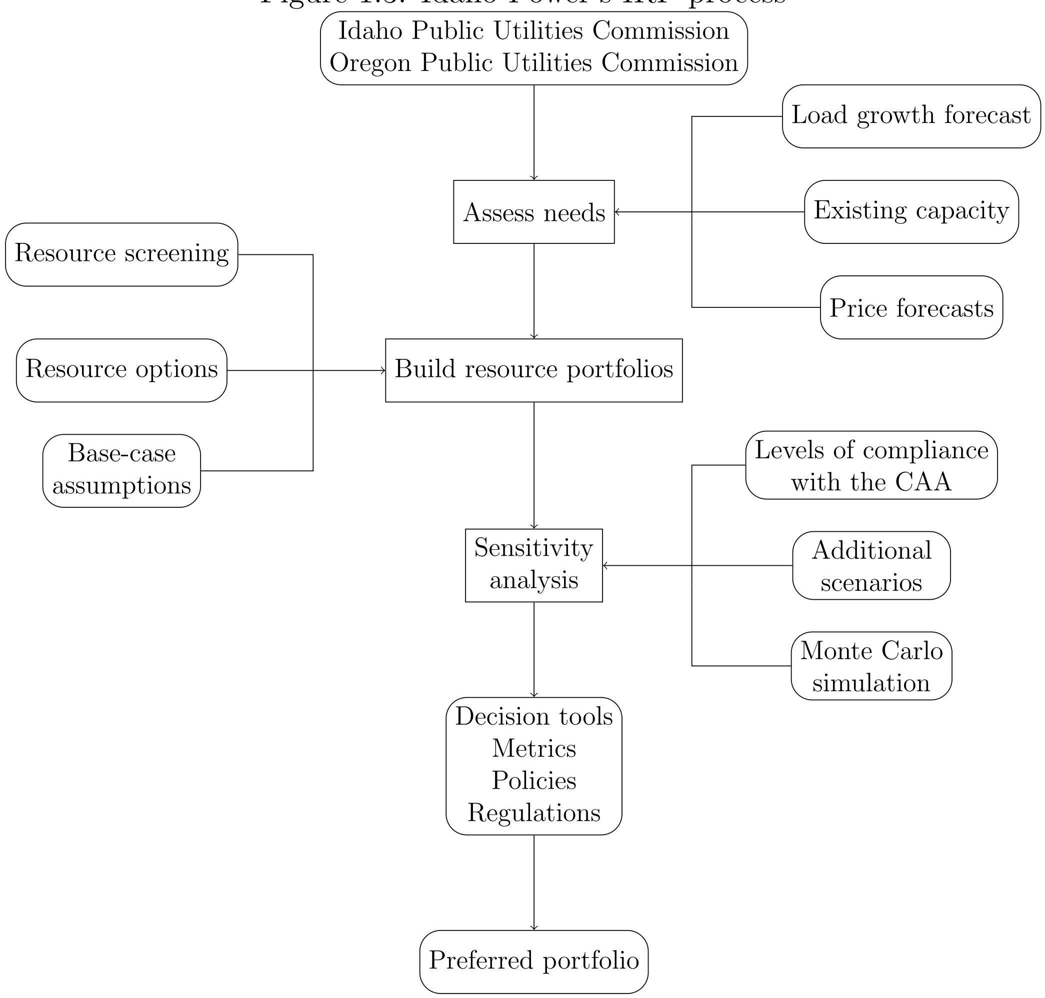
Table 1.2: Idaho Power's energy mix

Energy source	**Percentage**
Hydro	36
Coal	34
Natural gas and diesel	7
Market purchases	8
Power Purchase Agreements (PPAs)	
–Wind	9.8
–Biomass	0.6
–Hydro	2.4
–Natural gas	0.5
–Waste	0.3
–Geothermal	1.4
Total	100

portfolios (see Figure 1.3 for overview of process). Instead, their portfolios are constructed manually to meet the supply-demand gap. This is carried out in discussion with stakeholders and guided by the company's planning objectives such as reduced use of coal. In total, 23 portfolios were created and analysed. Idaho Power is currently most concerned about potential carbon prices and regulatory changes, so the most recent IRP portfolios all feature some level of coal retirement. Manual selection of portfolios allows Idaho Power to focus on what they perceive to be their greatest risks, allowing direct management of uncertainty. The costs of the portfolios were simulated over the 20-year planning period using Aurora^{XMP} with base case assumptions.

Sensitivity analysis of each portfolio was carried out by varying one of three variables: natural gas price, load, and hydroelectric variability. These variables were given log-normal or normal distributions and run with the portfolio over 100 iterations. Also included in the sensitivity analysis was level of compliance with Section 111(d) of the Clean Air Act (CAA(, which regulates carbon dioxide emissions. Based on the results, the 11 lowest cost

Figure 1.3: Idaho Power's IRP process



portfolios were chosen for further scrutiny. This analysis focused on the standard deviations of the cost of each portfolio over their 100 iterations. The portfolios with the lowest standard deviation changes over the 100 iterations were considered to be least susceptible to large year-to-year swings and therefore were deemed to be more robust choices. Tipping-point analysis was carried out for several of the best pairs of scenarios to see how capital price changes would affect the choice of one portfolio over the other. Based on these results, a preferred portfolio was eventually chosen.

1.2.3 Los Angeles Department of Water and Power

The LADWP is the largest municipal electricity utility in the United States [8]. The utility has 7,640 MW of owned capacity largely focused on coal (Table 1.3), and provides power to about 1.5 million customers in Los Angeles and the Owens Valley [9]. Unlike investor owned utilities (IOUs) like SCE and PGE, LADWP remains vertically integrated, owning and operating the bulk of its generation, transmission, and distribution systems. Because of this, LADWP follows an IRP process rather than the long-term procurement planning (LTPP) process mandated for IOUs, and their planning consequently has much in common with utilities in non-regulated jurisdictions.

LADWP divides customers into service categories when developing their load forecast. Econometric models are used for load forecasting for residential, commercial and industrial customer classes, while trend models are used for intradepartmental, street lighting, and Owen Valley customer classes. The utility also considers how electric vehicles may affect their load, and uses the California Energy Commission's (CEC) forecast for this customer class. The forecasts from these methods are modified by LADWP to reflect their programs in EE and DSM. A combined load forecast is developed from this input and used for the rest of the planning process. LADWP builds portfolios manually and then runs simulations of scenarios with the Planning and Risk model from Ventyx. Five portfolios were constructed for the 2014

Table 1.3: LADWP's energy mix

Energy source	**Percentage**
Eligible renewables	23
–Biomass and waste	6
–Geothermal	1
–Small hydro	1
–Solar	1
–Wind	14
Coal	42
Large hydro	4
Nuclear	10
Naturgal gas	17
Unspecified	4
Total	100

IRP; four of them reflecting LADWPs commitment to increasing their RPS generation, and one base case. Each of the RPS scenarios is built around a different GHG reduction strategy. The utility acknowledges the flexibility needed to integrate solar and wind by including pumped storage hydro and natural gas in all portfolios. The California Public Utility Commission's (CPUC) required loading order results in DSM and EE being considered as supply-side resources rather than modifications of the load, but they do not compete directly against other resources because of the manual portfolio selection. Sensitivity analysis is carried out using deterministic high and low forecasts for coal, natural gas, and CO_2 prices, using the Planning and Risk model. For coal and natural gas prices, the high and low forecasts are 10 percent above and 5 percent below the base case, respectively. Once portfolios have been simulated, the results are compared against each other using a detailed scorecard. LADWPs assessment criteria are reliability, environmental stewardship, and economic (cost) considerations. Once a preferred portfolio is identified, it may be modified further to reflect these criteria or to comply

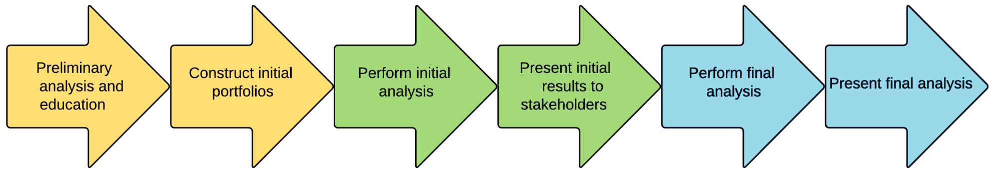


Figure 1.4: NWPCC's IRP process

with new policy directives. The IRP also includes a short term action plan, outlining the procurement actions to be taken in the first four years of the planning period.

1.2.4 Northwest Power and Conservation Council

The NWPCC is a regional organisation created in 1980 with the passing of the Pacific Northwest Electric Power Planning and Conservation Act. The main role of the organisation is to develop the 20-year power plan for the Pacific North West (Washington, Oregon, Idaho, and Montana), updated every five years[10]. The latest iteration is the sixth power plan, to be supplanted by the seventh in October 2015. The plan covers regional energy planning but does not guarantee that local capacity needs will be met. The optimisation model used by the NWPCC is MS Excel-based[11] and therefore is easily accessible to a majority of programmers. The model is called the Regional Portfolio Model, or RPM. Another model, GENESYS, is used for assessing the reliability of the plans produced, simulating loss of load probability and other reliability measures. HydSim, from the Bonneville Power Administration, is also used, to simulate hourly hydroelectric generation based on regional hydrological data.

The NWPCC states in their sixth plan that the plan should be explorative rather than predictive, and that the chosen plan should be robust in a wide range of potential conditions because of the uncertainty of foresight. To accommodate this, the plan includes decision criteria to evaluate risk in addition to the optimisation. In terms of scenario selection, NWPCC allows prices, load, and other variables to vary beyond historical levels, thereby including scenarios which are unlikely but possible. This is in recognition of some of the unprecedented changes that have occurred in the energy industry and the economy in the recent past.

Three load forecasts are developed by the NWPCC using their regional production-cost model, each forecast corresponding to certain economic drivers. Individual classes of customer are assigned separate growth rates based on economic and demographic trends, and the results are combined to form a base-case load forecast. The eventual base-case forecast was for 1.2 percent growth in demand per year over the duration of the planning period. In addition, two other forecasts were developed to represent high and low demand conditions. The low demand forecast reflected slow recovery from the recent economic recession and therefore low power demand, with growth of 0.8 percent per year. The high forecast was used to demonstrate robust recovery, using a growth rate of 1.5 percent per year.

The Excel-based RPM simulates each manually constructed resource portfolio against 750 scenarios, with quarterly time steps over a 20 year planning horizon. The model records the net present value of the costs for the portfolio in a given scenario, and repeats this for all scenarios, building a distribution of costs for that portfolio. The introduction of increasing quantities of wind power has increased the need for load-following capacity, and this is reflected in the choice of resources for the portfolios. Wind is also given a flexibility penalty between \$6 dollars/MWh and \$12/MWh to reflect the need for this ancillary capacity. The NWPCC uses TailVaR_{90} as their measure of portfolio risk. This is the average of the highest ten percent of the net present value cost outcomes associated with a given portfolio across all 750 scenarios. A preferred portfolio would likely be among the portfolios with both low expected costs as well as low TailVaR_{90} values and hence a low risk of high costs. This captures not just the probability of an undesired outcome, but also the magnitude. With each portfolio then having an average net present cost and TailVaR_{90} value, they can be plotted to determine the feasibility space and the efficient frontier.

The model times resource additions not by in-service date but by earliest construction date. This is also a risk management strategy, as inaccurate forecasts can lead to both over- and under-construction. The earliest construction date is the point beyond which it is not possible to change the choice of resource. Decisions on resource addition are made at each time step based solely on trends and information available up to that point; the model has no foreknowledge and may have to correct at a later time-step a decision that was taken earlier. This gives a realistic view of how decisions are made and altered over time, allowing eventual identification of a portfolio that is less sensitive to wide-ranging uncertainty rather than simply the least-cost for a given scenario. Sensitivity analysis is carried out in the GENESYS model by varying seasonal prices, hydro conditions, and load. The model generates random profiles for these variables on an hourly basis. To preserve the correlations between the variables, the random profiles are generated with a correlation of 0.95 between them. Transmission constraints are also studied because Idaho is summer-peaking while Oregon and Washington are winter-peaking areas. Inadequate transmission capacity could therefore hamper the ability of utilities in neighbouring regions to trade energy.

The NWPCC also comments on the transparency of the modelling process, stating that stakeholders and the public should feel that a model is not a black box and should be able to see how their concerns translate into the model. This is addressed in the first part of NWPCC's IRP process (see the yellow tabs in Figure 1.4), where preliminary analysis and education includes discussion of how the model works and uses input data. Initial portfolio construction also involves stakeholders and may be carried out immediately after preliminary analysis and education to ensure that understanding of the former carries over to the latter. Later stages also include further stakeholder input on the initial results and seek data for sensitivity analysis. One option that was identified for increasing confidence in the model is to run the same inputs in a different model, such as Aurora^{XMP}. Wildly dissimilar results would point to underlying differences in assumptions and model structure, and could be used to highlight whether the assumptions and structures are valid.

1.2.5 PacifiCorp

PacifiCorp operates 10,400 MW of capacity and serves 1.8 million customers in Oregon, Washington, California, Utah, Idaho, and Wyoming [12]. Five of these states have IRP requirements, and while Wyoming does not, it requires utilities that file IRPs outside the state to also file these with its state utility commission [3]. PacifiCorp therefore faces the challenge of implementing system-wide planning that fulfils the requirements of six different jurisdictions. The IRP is updated every two years, with a planning horizon of 20 years (see Figure 1.5 for overview of process). As of 2013, PacifiCorp's generation was dominated by coal, followed by natural gas (Table 1.4).

PacifiCorp uses econometric models to develop load forecasts based on historical usage, weather, economic growth and customer behaviour/changes. Different forecasts are generated for different user groups, with groups that have similar usage patterns combined together. These forecasts are then combined to give the overall system forecast. PacifiCorp assumes an average annual energy growth rate of 0.85 percent for its single base-case forecast.

PacifiCorp considers DSM as a supply-side resource in the portfolio-building process, rather than as a load modifier. This allows DSM to compete directly with other resources and can lead to a lower overall portfolio cost. Considering DSM as a resource can have beneficial effects on uncertainty, as new generation can be delayed until larger uncertainties are resolved. The

Table 1.4: PacifiCorp's energy mix

Energy source	**Percentage**
Coal	62
Natural gas	17.4
Hydro	6.3
Wind	8.1
Biomass	0.5
Geothermal	0.4
Solar	0.03
Unspecified	5.3
Total	100

utility focuses on resource acquisition in the first ten years of the IRP. To assist this process, PacifiCorp also develops an action plan for the first two to four years of this period, focusing on potential regulatory changes and economic triggers that could dramatically change the resource portfolio.

PacifiCorp's main approach to uncertainty is to analyse a large number of scenarios. Scenario development occurred in consultation with stakeholders. 19 input scenarios (core cases) were chosen, each with varying assumptions about five key variables: prices and timing of CO2 regulations; natural gas and electricity prices; assumptions about RPS policies and federal tax incentives; policy assumptions around coal-fired plants and retrofitting to meet regional haze regulations; and kick-in times and ramp rates for DSM and efficiency resources. In addition to the 19 scenarios, PacifiCorp also had five different scenarios around the construction of new transmission capacity; when applied to each of the 19 core cases, this created 94 scenarios. Sensitivity scenarios were also used to look at alternative load forecasts and at resource-specific assumptions. Twelve of these sensitivity scenarios were considered, each typically paired to a core case. In total 106 scenarios were developed and modelled. The company also attempted to address the uncertainty around an economic level of renewable resources. PacifiCorp ran two rounds of portfolio optimisation using System Optimizer. The first set included only scenarios in which no RPS requirements were included. This allowed all resources to compete for allocation in the portfolio based on lowest cost, including renewables. From these results, the company obtained an idea of the level of renewable resources that was economic for the simulated scenario. The second set of scenarios had equivalents of the first set but with RPS requirements of varying levels. The renewable resources chosen from the first run for each scenario were forced into the portfolio for this second run of the scenario as a minimum level of renewables. Any gap between this level of renewables and the RPS requirement was filled with new renewables chosen through RPS Scenario Maker, an optimisation model for renewable resources. Once these resources were input into System Optimizer as fixed requirements, System Optimizer was run again to compile the rest of the portfolio, which may or may not add renewable resources in addition to those forced into the portfolio. Sensitivity analysis was then carried out for all portfolios developed through System Optimizer. The Planning and Risk module of System Optimizer was used for this. The uncertainty here was largely handled by having a range of projections for the most important variables affecting portfolio cost. Three different carbon prices per short ton (zero CO_2 price, medium with \$16 in 2022 rising to \$26 in 2032, and high with \$14 in 2022 rising to \$75 in 2032) were input as projections into PaR. The model also used Monte Carlo simulation to get varied projections of load, gas prices, electricity prices, hydro energy availability, and thermal unit availability. For each portfolio, 100 simulations were run with these variations in underlying variables, giving 100 different cost estimates for each portfolio. The top-performing portfolios from the PaR model were chosen based on the frequency with which they were below the mean values and in the upper tail (i.e. having one of the five highest values after the Monte Carlo simulation) of the simulated variables. The primary criteria used for judgement were: risk-adjusted cost, CO_2 emissions, and supply reliability. One portfolio was

Table 1.5: Public Service Company of Colorado's energy mix

Energy source	**Percentage**
Coal	53
Natural gas	25
Wind	19
Hydro	2
Solar	1
Total	100

then selected as the preliminary preferred portfolio, based on the companys assessment of the portfolio's risk-adjusted PVRR, carbon dioxide emissions, and supply reliability (specifically measured as average annual Energy Not Served).

1.2.6 Public Service Company of Colorado

The Public Service Company of Colorado (Public Service) operates as part of Xcel Energy Inc. in Colorado [13]. The company serves 1.4 million customers in Colorado with a system capacity about 7,600 MW. This capacity counts for about two-thirds of the load, and Public Service relies on power purchases to augment their generation. Public Service relies heavily on coal and natural gas with significant levels of wind energy as well (Table 1.5).

Electric resource planning in Colorado occurs in two phases. During phase 1, the utility compiles information on their existing generation fleet, assesses need for additional resources, and plans how to acquire those resources. This phase leads to the development of the "Electric Resource Plan" or IRP, and a Resource Acquisition Plan (RAP). The IRP is filed with the Colorado Public Utilities Commission and updated every four years. Once the IRP is approved by the Commission, phase 2 begins, in which the company implements the IRP and the RAP. The overall process is illustrated in Figure 1.6.

Public Service is facing significant changes in its operating environment,

Figure 1.5: PacifiCorp's IRP process

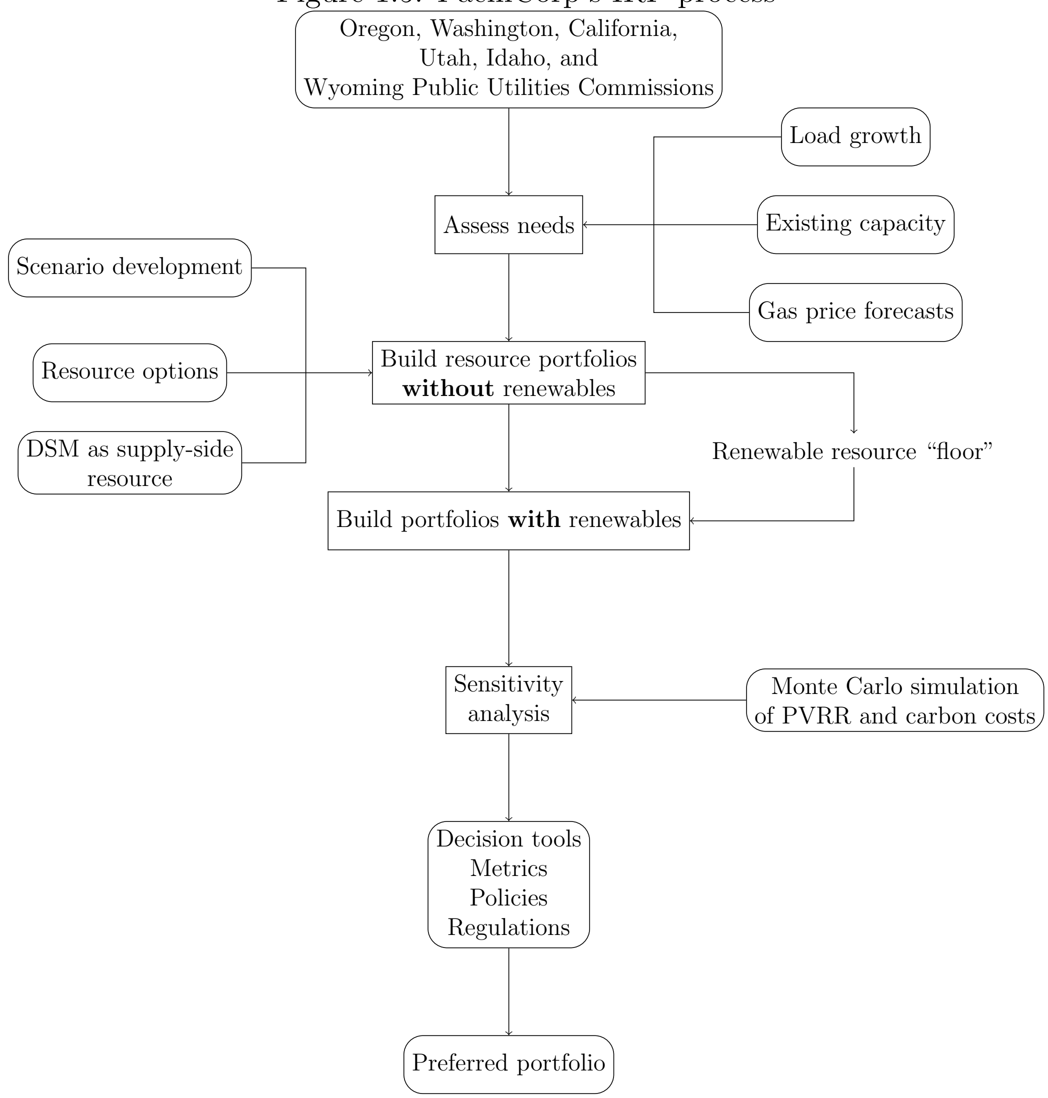
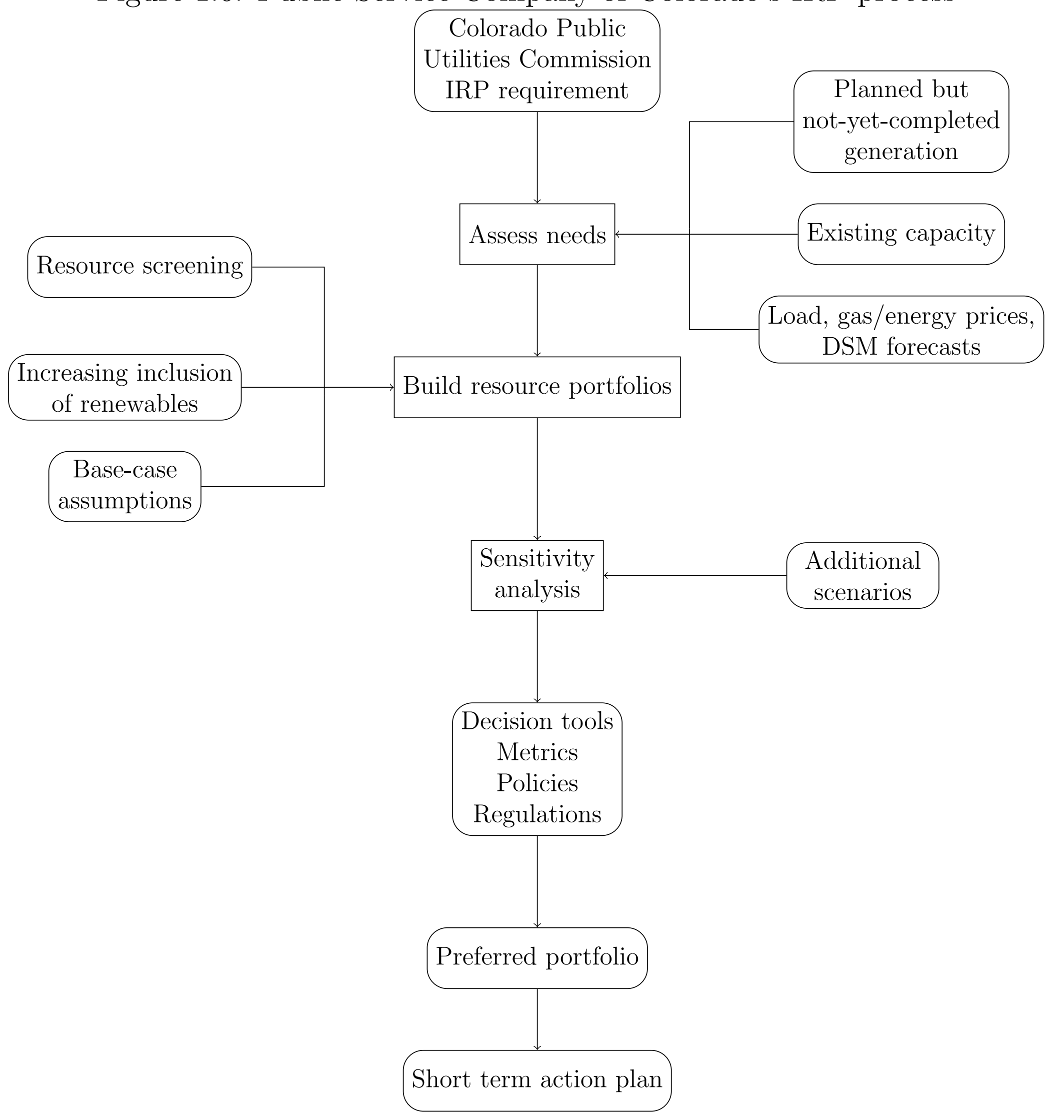


Figure 1.6: Public Service Company of Colorado's IRP process



as outlined in their 2011 IRP. In common with other utilities, the recent recession has affected demand for electricity and economic growth forecasts are still uncertain. Public Services electric load growth forecast over the RAP period (2011-2018) is 292 MW, compared to the 2007 forecast of 1,000 MW over the same period. Uncertainties also surround the potential withdrawal of large customers such as the City of Boulder; if this occurs, the 2018 demand forecast could drop to 5 MW. To comply with the Clean Air-Clean Jobs Act (CACJA) passed in 2010, the company is retiring 600 MW of coal, fuel switching from coal to natural gas on another 450 MW of generation, and installing emissions controls on another three coal-fired units over the next six years. Public Service uses a planning period of 40 years, extending from 2011 until 2050. DSM is included as a modification of the load forecast, not as a separate resource that competes against supply-side resources. The load modelled in their optimisation model, Strategist, consists of the projected load plus the planning reserve margin, in this case 16.3 percent. Public Service prepares both a base-case (median) load forecast and high and low forecasts for sensitivity. The base-case load forecast is for growth of 0.3 percent per year over the planning period, while the low forecast is for a reduction of 0.6 percent per year and the high forecast predicts growth of 1.1 percent per year. The forecasts are based on economic projections from IHS Global Insight, Inc. Monte Carlo simulation was used to develop the alternative high and low forecasts, which are the borders of a confidence envelope of 70 percent about the median forecast. The IRP stated that based on the load forecast, Public Service intends to delay most new generation construction and instead fill the gap with power purchases. This is a risk management strategy whereby the company avoids high capital costs and waits for uncertainty to resolve before committing to new generation. The risk incurred instead is that power prices may increase higher than expected over the short term. Uncertainty was primarily dealt with by running multiple scenarios. The concern appears to be around renewable resources and whether regulations will force a certain level of renewables to be used. By inputting increasing amounts of forced renewable resources into the least-cost baseline case and re-optimising through Strategist, Public Service can see the range of costs that could occur. Sensitivity analysis on the nine portfolios, undertaken with the Planning and Risk model, gives an estimation of how robust the portfolios are if their underlying assumptions change. For the sensitivity analysis, inputs such as CO2 price, tax credits, gas prices, and sales were varied to reflect a different future. Several features of the companys 2011 IRP are noteworthy. One of these is the inclusion of a clear contingency plan; the events most likely to cause a capacity shortfall are identified and clear actions to mitigate each event are listed. These range from near-term events like a PPA falling through to more distant events like slow construction of new generation. Public Service also takes an interesting approach to integrating wind energy. The company intends to increase their total wind generation, acquisition of which began under the previous RAP in 2004, to 2,100 MW by the end of 2012. This represents a sizeable portion of generation capacity that is intermittent, and the company plans for this uncertainty by also selecting other resources that can be dispatched within a 30-minute time frame to manage this fluctuation. As utilities sometimes reject increased renewables for precisely this uncertainty, Public Services approach offers a contrasting example of how renewables can be integrated.

1.2.7 Tacoma Power

Tacoma Power is a division of Tacoma Public Utilities, operating in the Tacoma area of the state of Washington [14]. Tacoma Power is a public energy company, serving 169,000 customers and running a system that is dominated by hydro-power generation (Table 1.6). However, owned generation provides only about fifty percent of Tacoma Power's energy, as power purchase agreements with Bonneville Power Authority constitute over half of its energy. The utility is required to file a full IRP with the Washington State

Table 1.6: Tacoma Power's energy mix

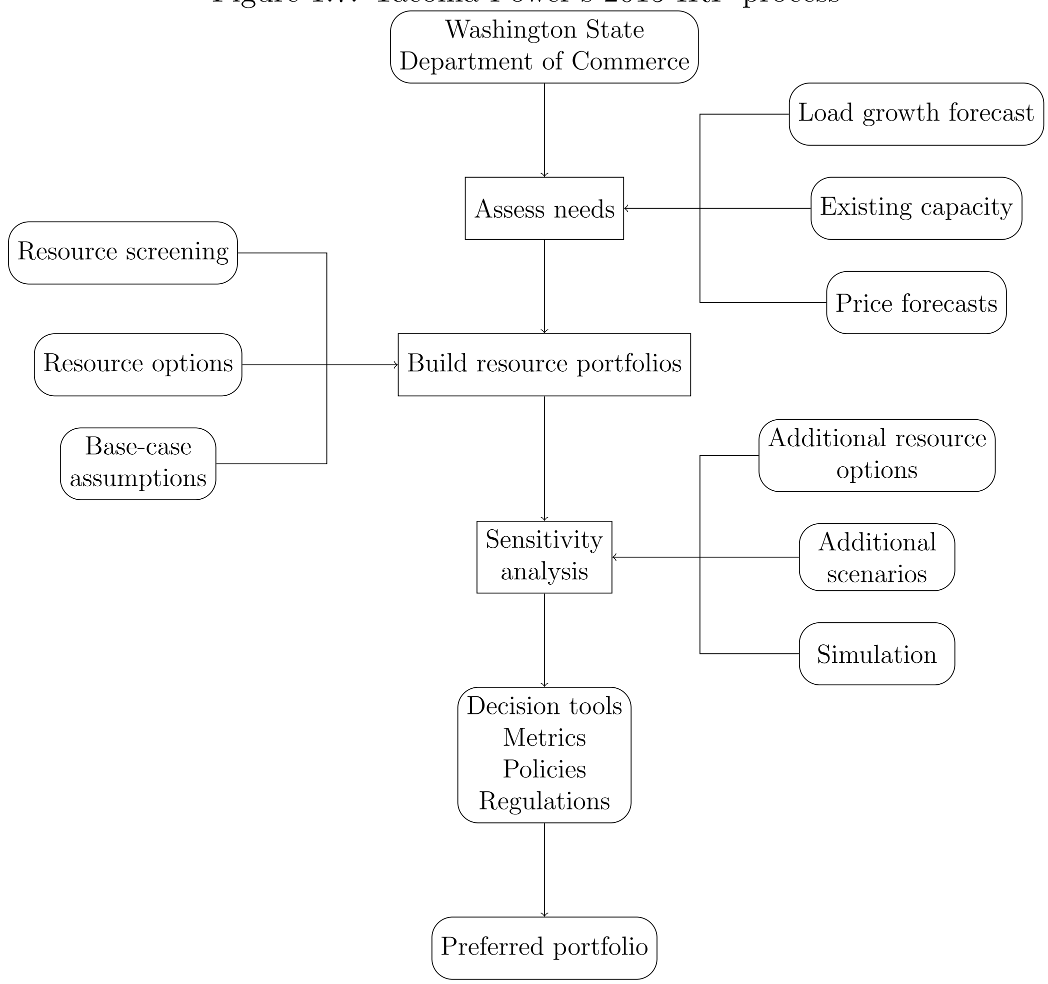
Energy source	**Percentage**
Hydro	90.6
Nuclear	6.1
Coal	1.2
Natural gas	0.5
Other(biomass, petroleum, waste, wind)	1.7
Total	100

Department of Commerce every four years, with updates required every two years. The IRP has a planning horizon of 15 years. Figure 1.7 presents an overview of the most recent planning process.

Uncertainty in rainfall and hydrology is the largest contributor to Tacoma Powers overall uncertainty. Tacoma Power handles this high variability in rainfall by planning to the lowest historical stream flow (since the 1930 water year). This means that in average years the utility runs a surplus, which it sells largely to the Bonneville Power Authority. Tacoma Power manages load uncertainty by dividing customers into different consumer categories and using different projection methods for each. For example, contract industrial customer load is forecast by analysis of historical trends and direct consultation with the customer. Customers like lighting services, which grow more predictably, have loads forecast by extrapolation of historical trends. Residential customer load is forecast by regression analysis based on demographics, weather data, and economic trends. Price forecasts are developed for Tacoma Power by Wood Mackenzie using Aurora^{XMP}, which Tacoma Power then modifies with a risk adder for gas price uncertainty and for carbon prices. Two price forecasts are considered in the planning, a high (75th percentile) and low (10th percentile) forecast.

In their 2013 IRP, Tacoma Power modelled their hydro operations with VISTA DDS (VISTA), a model from Hatch Ltd that optimises the opera-

Figure 1.7: Tacoma Power's 2015 IRP process



tion of their generating units. DSM was not considered to be a supply-side resource in Tacoma Powers planning instead it was modelled as a modifier of the load. One of Tacoma Powers aims in the 2013 IRP was to delay the need for new generation through DSM and increased efficiency. As hydro is the largest component of Tacoma Powers system, existing and planned hydro resources were simulated in VISTA as base load generation. The uncertainty that other utilities consider by multiple scenarios was considered by simulating the hydro portfolio with historical water years. The model counted the frequency of power deficits and surpluses with their chosen hydro portfolio over the course of the simulations and made an estimate of how often they are in surplus given the historical water conditions. The planning scenarios used the critical water year, with runs taking the average flow for the year as tests for how much surplus was expected under normal conditions. After the hydro portfolio had been run, other resources, such as combined cycle gas turbines (CCGTs(, wind, biomass, solar, and pumped storage, are then considered as add-ons to the hydro base portfolio and added to the simulation. As Tacoma Power considered increased demand to be their greatest risk, several scenarios with higher than expected load were run to see the ability of the portfolios to meet that demand. Sensitivity analysis was carried out using Crystal Ball. As load and water year are independent of each other, the model varied these separately. Load variation is assumed to be ± 15 aMW with a triangular distribution. The model then selected a load within this distribution, chose a random water year and ran the simulation. The process was iterative, with VISTA revising the shape of Tacoma Powers load forecasts and inputs into Crystal Ball, and Crystal Ball revising the resource portfolio. When the utility was satisfied that the process had produced a reliable portfolio, it was selected as the preferred portfolio.

Tacoma Power released their 2015 IRP in November 2015, using a different process to the 2013 IRP[15]. The utility now uses Plexos to simulate the operation of their portfolios over the planning period with four different

Table 1.7: TVA's energy mix

Energy source	**Percentage**
Coal	34
Natural gas	27
Nuclear	18
Hydro	
–Conventional	12
–Pumped storage	4
Renewables	
–Wind	4
–Solar/biomass	<1
DSM	3
Total	100

scenarios. As Tacoma Power is able to meet expected load growth with DSM and EE, the IRP showed no need for additional generation resources. However, in the interests of having analysis to fall back on if conditions change drastically, the utility screened potential resource additions and selected the most suitable ones for their system. The effect of adding these resources to the system was then tested by running simulations in Plexos, where each new resource was added to a particular portfolio as a block of 50 MW annually, and run against the four scenarios.

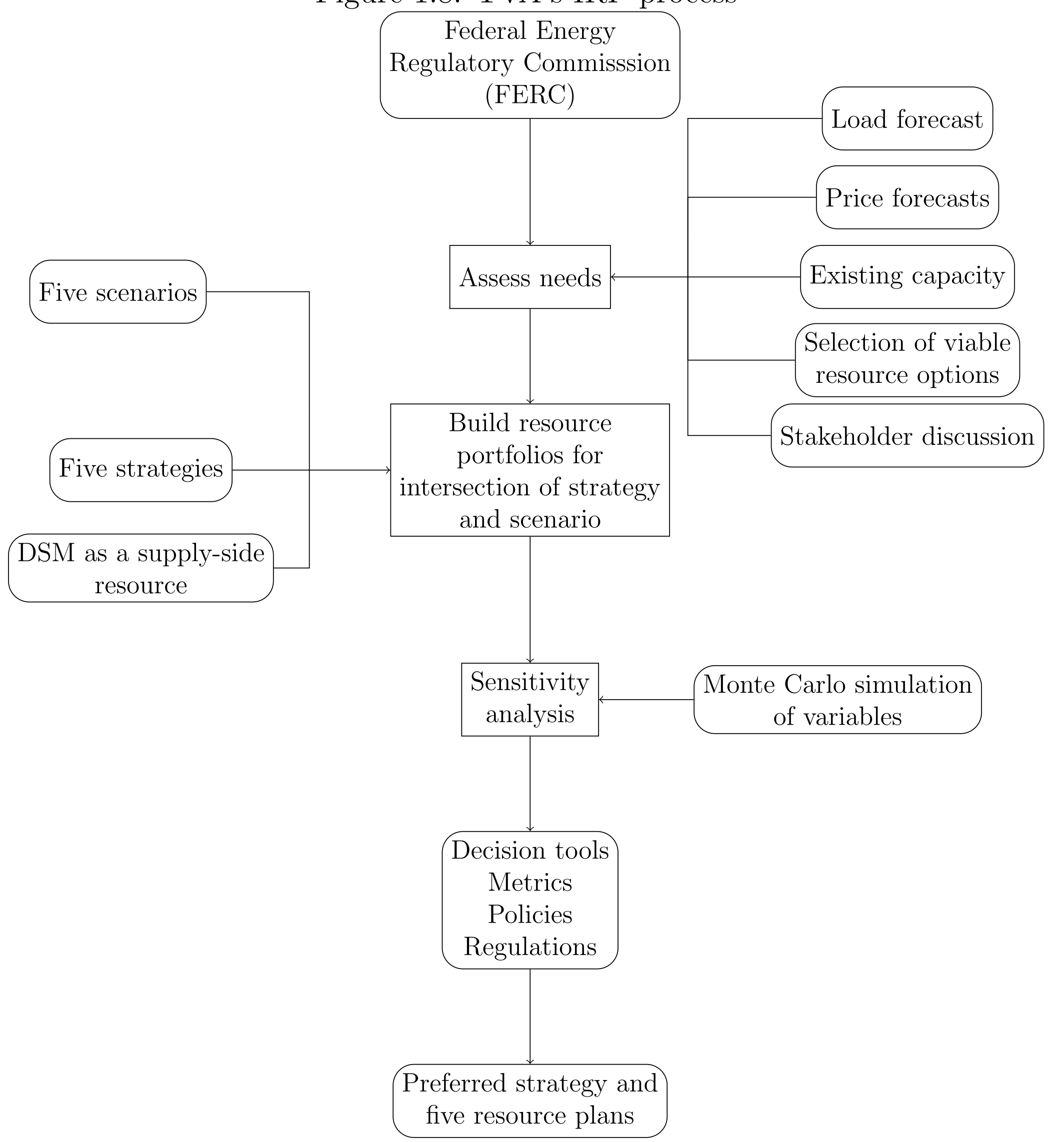
1.2.8 Tennessee Valley Authority

TVA is a federally-owned corporation covering most of Tennessee and parts of Alabama, Mississippi, Kentucky, Georgia, North Carolina, and Virginia [16]. TVA operates the largest public power system in the United States with 36,520 MW of capacity, serving 9 million customers. As of the 2015 IRP, coal and gas accounted for about 60 percent of TVAs generation (Table 1.7).

As a federal agency, TVA is obliged to file an IRP and environmental impact statement (EIS) under the National Environmental Policy Act of 1970 (see Figure 1.8 for outline of the full process). The 2015 iteration of the IRP is an update of the 2011 IRP, brought about by significant changes in the underlying assumptions of the 2011 IRP. The IRP is produced in conjunction with an environmental impact statement (EIS(, both of which must be submitted to the Federal Energy Regulatory Commission (FERC) every four years. The goal of TVAs IRP process is to identify an integrated resource plan that performs well under a variety of potential conditions, so robustness is favoured more highly than absolute least-cost. TVA uses statistical and mathematical models to develop their load forecast. The utility looks at key drivers of electricity sales - economic activity and growth, electricity prices, customer retention, and the price of competing energy sources - and estimates the load based on these variables. Historical records of power use are also included. These are combined to develop a single load forecast in consultation with stakeholders and directly-served customers. TVA constructs their overall forecasts from county-level forecasts.

TVAs planning process is scenario-based, and uses System Optimizer. Five scenarios are chosen, representing potential futures over which the company has no control, and based on what the company perceives the greatest uncertainties to be (e.g. gas price, carbon pricing, coal prices, economic growth, etc.). TVA then develops five resource planning strategies. These strategies represent decisions that are within the companys control, such as asset additions or change of fuel type. In the 2015 draft, there are five of these: traditional base case least cost; emissions reduction; focus on long-term market supply; energy efficiency; and maximise renewable energy capacity. Each strategy is then run against each scenario, modelled by System Optimizer, to generate a resource portfolio for each intersection. DSM is included in the model as a supply-side resource. Sensitivity analysis was carried out for each resource portfolio using the MIDAS model. This model uses a form of Monte Carlo simulation to create distributions of the under-

Figure 1.8: TVA's IRP process



lying variables. In this IRP, 72 Monte Carlo runs iterations were carried out for each portfolio. The sensitivity scenarios centred on addition of nuclear capacity, energy efficient and DSM effectiveness, pricing and performance of renewables, and high/low scenarios for power price, fuel price, carbon price, and load. In conjunction with their stakeholders and based on their strategic aims, TVA selected five broad metrics by which a portfolio would be assessed. These were cost, financial risk, stewardship, Valley economics, and flexibility. Within these categories, specific targets or measures were defined to evaluate each strategy for every scenario. These were combined into a scorecard, under which each strategy could be scored for the chosen measures over all five scenarios. In total five scorecards would be made, one for each strategy. TVAs planning process is particularly transparent. The optimisation model is used to compile resource portfolios, but it is actually the strategy that is being evaluated. The eventual preferred strategy will have five resource portfolios, corresponding to the five scenarios, all scored against the companys long-term aims. This gives the company a broad picture of the mix of resources that will mesh well with the chosen strategy. Planning uncertainty is handled by having several scenarios, but also by not using probability to select what futures are most likely. Instead, issues that concern the company and stakeholders are developed into scenarios with less focus on whether it is a most likely future. Because these scenarios are not based on extrapolation using historical data, they have the possibility of capturing behaviour that has not happened before. Given current debate about stationarity in weather patterns and climate, this is a valuable consideration.

1.2.9 Californian IOUs and Energy Context

California is different from most of the other North American jurisdictions studied because of its deregulated energy market. Instead of the type of IRP process typically followed by vertically integrated utilities in regulated markets, a deregulated market is dominated by competition for short term power purchase contracts [17]. Separate companies handle generation, transmission, and distribution. The role of a utility is generally that of distribution, not generation, although some utilities will have generation capacity to serve customers that do not opt for unbundled service. New generation is procured by competitive generation companies in response to market conditions, so there is little incentive for long-term resource planning on the part of utilities. The IRP process was replaced with a planning framework called an LTPP, which focused on procurement through power purchases. The CPUC began requiring utilities to file an LTPP in 2004, with updates every two years. Between 2004 and the present, however, the LTPP has split into two streams; one dealing with short- to mid-term procurement through purchases (bundled procurement plan), and one dealing with long-term system reliability and capacity expansion (system resource plan). The return to longer-term planning is partly due to the increased volume of renewable resources imposed by the state. California is pursuing an ambitious policy towards reduction of GHG emissions and as part of this requires that utilities procure at least 33 percent of power from renewable resources by 2020 [18]. As renewable resources frequently have more intensive capital costs and higher energy costs than traditional generation [17], investors have been reluctant to commit to these resources without guarantee of cost recovery, and longer-term planning has helped to alleviate this issue. For both plans, the load forecast is developed by the CPUC in conjunction with the CEC and California Independent System Operator (CAISO), and provided to the utilities along with a standardised set of planning assumptions and scenarios [19]. The CPUC updates this planning information every two years. CAISO, which has oversight of the transmission planning process (TPP), uses similar assumptions, and in 2014 the two organisations decided to coordinate and use the same assumptions and scenarios for both processes[20]. The utilities construct portfolios that will meet the load forecast at least cost to the customer and that accord with the required state loading order (EE $\rightarrow$ DSM $\rightarrow$

renewables $\rightarrow$ efficient fossil fuels) and renewables targets[18]. Hydroelectric resources with nameplate capacity greater than 40 MW per unit operated are not eligible to be counted as renewable resources [8], so a distinction is made between small hydro and large hydro in the loading order. Because of these constraints, the IOUs typically compile portfolios without the use of models and therefore have fewer scenarios than utilities that use models for portfolio development [21][22]. The utility submits its LTPP to the CPUC for approval and, if the plan is approved, begins to send out requests for offers (RFOs) for construction of new generation.

Pacific Gas and Electric

PG&E operates in the state of California, supplying electricity and gas to the central and northern areas of the state. With a customer base of about 5.4 million electricity customers and owned capacity of 7,677 MW , the company is one of the largest load serving entities in the WECC [24, 23]. Table 1.8 provides the breakdown of PG&E's energy sources as of 2014 [9]. Prior to 2004, PG&E submitted a short-term procurement plan (STPP) every year to the CPUC. From 2004 onwards, the company has filed an long-term procurement plan (LTPP) every two years.

PG&E obtains their load forecasts from the CEC. The utility then can use this as a base-case but may also modify their forecast and include other forecasts if they can show good reason for doing so. PG&E uses a low forecast based on the CECs low forecast; a base forecast based on the CECs high forecast; and a high forecast based on the CECs high forecast with additional 0.3 percent growth per year. As load in deregulated jurisdictions depends heavily on changes in prices and the market, planning for procurement has a relatively short planning period of generally six to 12 months. Planning in this case occurs in consultation with CAISO. Longer term planning dealing with system capacity, typically with a horizon of ten years, occurs through

Table 1.8: PG&E's energy mix

Energy source	**Percentage**
Eligible renewables	22
–Biomass and waste	4
–Geothermal	5
–Small hydro	2
–Solar	5
–Wind	6
Large hydro	10
Nuclear	22
Naturgal gas	28
Unspecified	18
Total	100

the CPUC. Portfolios are constructed manually by PG&E to meet the load identified in their needs assessment, and run against the scenarios provided. The performance of each portfolio in each scenario is evaluated with the use of metrics that reflect the most important concerns of the utility. From this evaluation, a preferred portfolio is identified and submitted to the CPUC for approval[25]. Uncertainty is included largely through scenario modelling. In the latest iteration (2014), the scenarios were built by collaboration between the CPUC, the CEC, and CAISO, and given to all utilities as a standard set of futures [19]. These three agencies also develop and maintain the Excel-based tool used by several Californian utilities to simulate their portfolios and construct additional scenarios of their own. The Plexos platform is used for modelling in PG&Es LTPP process. Uncertainty is included by having a range of deterministic projections for a variable or Monte Carlo simulation to sample from a distribution of a variable [26]. PG&E explicitly considers three types of uncertainty in the LTPP[21]. The first is short term cyclical uncertainty, such as weather, hydro conditions or forced outages. These are often partially covered by reserve margins, and are handled by assigning probabilities and distributions to the variables. The second is long-term structural uncertainties, which are not covered by reserve margins, and include such variables as long-term load growth, potential movement of customers to community choice aggregator schemes (governmental entities to serve local residential and business energy needs), and changes in regulations that govern resource adequacy. The third is long-term commercial uncertainties, also not covered by reserve margins, and includes risks like delay in completion of new generation facilities, problems in obtaining permits, and delay in approval for new projects. Each general uncertainty is broken down into specific events or concerns and built into a scenario. Risk is identified by running Monte Carlo simulations for each portfolio and generating a distribution of portfolio cost. The to-expiration value-at-risk for each portfolio is then used as a measure of the risk of a portfolio having high costs[25]. Because of the separation of planning into two streams dealing with procurement and system capacity, most of PG&Es risk management is typical of financial management (e.g. hedging in accordance with regulations, etc.). The eventually identified preferred portfolio of purchases is submitted to the CPUC and CAISO for approval. All purchases and transfers are then conducted through CAISO.

Southern California Edison

SCE serves 14 million electricity customers in central and southern areas of California. The company is the largest subsidiary of the public utility company Edison International. SCE generates about 16 percent of the power it supplies, with the remainder coming from market purchases [27]. The utilitys owned generation relies on natural gas and a selection of renewable resources (Table 1.9). SCE still owns its transmission system although it was forced to sell some of its generation assets as part of the deregulation of the California energy market in the late 1990s. To comply with the states RPS regulations, SCE sold its share of the Four Corners coal-fired plant in 2012.

In addition, the San Onofre Nuclear Generating Station, of which SCE held a 78 percent ownership stake, was closed in 2013.

Table 1.9: SCE's energy sources

Energy source	**Percentage**
Eligible renewables	22
–Biomass and waste	1
–Geothermal	9
–Small hydro	1
–Solar	1
–Wind	10
Coal	6
Large hydro	4
Nuclear	6
Naturgal gas	28
Unspecified	34
Total	100

SCE also obtains their load forecast directly from the CPUC/CEC. SCE uses CAISOs Load and Resources Analysis (L&R) tool to determine its specific service area needs[22]. The L&R tool identifies shortages in various load regions by subtracting the expected load for the area from the available generating capacity in that area. The user is able to choose from several standardised planning assumptions in the tool, for example choosing a higher or lower load forecast. The utility also uses an additional forecast developed through econometric modelling by HIS Global Insight for sensitivity purposes.

Portfolios are compiled manually by the utility in discussion with stakeholders. These are then run against the standard scenarios defined by CPUC, CEC, and CAISO. The best performing portfolio, according to the companys pre-chosen metrics, is chosen as the preferred portfolio. The least-cost portfolio is not necessarily the preferred portfolio if other portfolios are of similar cost but offer better outcomes on other valued criteria such as reliability or RPS compliance. Sensitivity is considered by running additional scenarios that deal with shifts in market prices, and by using Monte Carlo simulation for distributions for fuel and power prices. SCEs process in general resembles that of PG&E and other investor owned utilities (IOUs) in California.

1.2.10 International utilities

Eskom - South Africa

Eskom is one of the 20 largest energy producers in the world by generation capacity, with owned generation of 41,194 MW. Eskom was founded in 1923 as the Electric Utilities Commission and converted in 2002 to a public company. The company is wholly owned by the government of South Africa, generating 95 percent of the electricity used in the country and 45 percent of the electricity used in Africa [28]. The companys latest IRP (Integrated Resource Plan for Electricity 2010-2030) was filed in March 2011 with the Department of Energy. The plan is expected to be updated at least every two years [1]. The company relies overwhelmingly on coal-fired generation (90 percent in 2011) with contributions from hydro (5 percent) and nuclear (5 percent). The hydro, however, is imported overland from Mozambique. Natural gas for peaking generation accounts for less than 1 percent and contributions from renewables are insignificant. Eskoms IRP process begins within government, initiated by the Department of Energy (DoE). A first round of consultation takes place with the public and other stakeholders to identify concerns and opportunities. Five scenarios are then developed by working groups in the DoE and Eskom, representing different policy directions. These scenarios are input into Plexos, which uses optimisation to create least cost resource portfolios. The portfolios are analysed and modified by various working groups to build a balanced portfolio that addressed governments risk concerns and objectives. In the current IRP, these concerns were:

1. Reduce carbon emissions
2. New technology uncertainties (cost, lead time, operability, learning rates)
3. Water usage
4. Localisation and job creation
5. Southern African regional development and integration
6. Security of supply

The portfolio chosen from this process is designated the Revised Balanced Scenario (RBS). The DoE then commences the second round of consultation with the public, industry, and other stakeholders. Results from this consultation process (in the 2011 IRP, issues such as changes for costing of nuclear plants, learning rates, and disaggregation of solar technologies were included) are taken and added to the scenarios in the second round of optimisation. Again, the resulting portfolios are assessed for fit with government policy, and then a final resource portfolio and plan is chosen, designated the Policy-Adjusted IRP. Uncertainty in this process is dealt with by having several scenarios, informed by industry, government, and the public. The two rounds of consultation in this process allowed input into what original scenarios were developed and into the assumptions used for the modelling in the first run. Eskom also recognises the risk of relying heavily on a single fuel source (coal) and to buffer this has chosen to move towards a more diversified portfolio. This IRP process relies less heavily on optimisation and more on decision analysis. The aim is not so much least-cost as reliability and stability. Risk in each portfolio would ideally be monetised and added to the cost of the portfolio for full analysis. However some risks are not easily monetised, so the second best approach would be to assign probability distributions to each risk and use the standard deviation as a measure of the risk. This was also not done, due to lack of time and discussion about the most appropriate distribution for each risk. The third option, used in the IRP, was for simple assignment of risk by expert opinion. Each aspect of risk for a particular technology as given a risk value, and the combined weighted risk values were assigned to the technology, and then to the portfolio containing that technology. This allowed working groups to make decisions on which portfolios were most robust. Contingency planning was also part of managing risk in this IRP. For each technology and planned capacity expansion, decision trees were used to outline the decisions that should be taken to maintain adequate supply if particular events occurred. This method seems to incorporate Robust Decision Making (RDM) techniques, in which an action plan is developed backwards, based on avoiding or mitigating events that could cause the plan to fail.

1.3 Conclusion

This report has presented the IRP process for a sample of electric utilities across North America. An effort has been made to provide a broad picture of IRP-using utilities, with diversity in location, generation, and market structure. Our research suggests that two main methods of planning are used among the surveyed utilities: a method based on manually constructed portfolios; and a method based on development of scenarios and use of an optimisation model to construct and test portfolios. BC Hydro's current planning process falls into the scenario-planning group and is largely typical of that class of planning.

Chapter 2

BC Hydro's approach to uncertainty in the 2013 IRP

This section was prepared as a report for BC Hydro's Energy Planning group, recommending a modified approach to their uncertainty management. Some information about specific models and model operation has been removed. References for this report appear in the bibliography section of the thesis.

2.1 Introduction

BC Hydro's long term planning process involves the production of an IRP every five years. The plan covers a period of 30 years from the year of plan publication and outlines the capacity expansion strategy for the utility. As with all forms of planning, BC Hydro must work with limited and changeable data to develop a strategy that will be robust in an uncertain future. This report outlines BC Hydro's present modelling set-up and recommends a revised framework to deal with uncertainties typically encountered in the development of long term capacity expansion plans.

2.2 Summary of recommendations

A modified IRP process is laid out in the following steps:

1. Determine what are the primary objectives and performance measures for the IRP process and portfolio analysis and assessment,
2. Develop specific metrics to assess the performance measures,
3. Use an optimisation model to develop optimal portfolios,
4. Screen and select a set of portfolios to analyse more rigorously,
5. Use HYSIM/GOM to simulate developed portfolios under a range of conditions and observe their behaviour,
6. Compare the portfolio performances with the use of clearly defined metrics and trade-off analysis,
7. Select a portfolio that performed well across all metrics.

This process would require the implementation of several recommendations to change the current process. These are:

- Use HYSIM/GOM for further sensitivity analysis of individual portfolios, expanding to include simulating with alternative loads, gas prices, and energy prices as well as the current alternative water years. HYSIM/GOM is capable of this analysis, although minor changes will be needed to streamline the process and automate for multiple input scenarios.
- Develop metrics and scorecards and/or efficient frontier analysis for assessing portfolio performance;
- Build a model or interface capable of changing the inputs to HYSIM automatically for multiple runs, to streamline the process of running the increased number of simulations;

2.3 Portfolio development

The utilities studied in a comparison of energy planning methods conducted for BC Hydro [29] used two methods for developing portfolios for IRP. The portfolios were either chosen manually, with the utility deciding on the inclusion of individual resources (portfolio-based planning), or were selected by a model using some form of optimisation (scenario-planning).

Manual portfolio development option has the advantage of directness because the utility directly selects the resources needed to satisfy their load. The disadvantage is that for a large load-resource gap, a large number of resource combinations can fill the gap and it can be difficult to select the best combination manually. This method appears to work best when the options are constrained or the load-resource gap is small and can be easily filled by one or two resources. Manual portfolio development occurred among the Californian investor owned utilities (IOUs) because of their constraints under the state loading order, which prevents them from using particular classes of resources until all affordable alternatives of a more favoured class of resources have been exhausted[17][19]. Tacoma Power also used manual portfolio development because they had no need of new resources and simply chose to test an addition to their system of 50 annual megawatts (aMW) of energy in different forms[15]. BC Hydro shares some similarities with the Californian IOUs because of constraints imposed by the British Columbia Utilities Commission (BCUC) and the British Columbia Clean Energy Act of 2010. These include a requirement for BC Hydro to achieve electricity self-sufficiency by 2016, meaning that BC Hydro must be able to meet electricity supply obligations by 2016 and each year thereafter with energy generated in British Columbia; minimum targets on the percentage of energy that must come from renewable sources (93 per cent); target reductions in green house gases (GHG); and demand reduction of at least 66 per cent by 2020 [30]. However, BC Hydro has many options to fill their load-resource gap, even under these constraints, and the gap between generation capacity and load is such that a combination of one or two resources will not be sufficient to make up the deficit.

The other method used was scenario-based planning where the utility varied underlying variables to produce an array of scenarios and then used an optimisation model to build portfolios of resources that were optimal for each scenario. This method takes some of the ambiguity out of resource selection, as the optimisation model chooses resources based on defined objective functions and constraints, making the choice easier to justify than direct manual utility selection. This is important for a government-owned utility as it must be transparent in its planning processes. Models also tend to be more efficient at calculating the costs and benefits of including a particular resource in a portfolio than a human, especially when there are many resource options available and the load-resource gap requires combinations of many of resources. The disadvantage of this method is the difficulty in formulating an all encompassing objective function that captures several non-commensurate objective function terms. Size also appears to play a role, as the utilities review [29] highlighted that larger utilities tend to use scenario-based planning rather than portfolio-based planning, partly because the difficulties in selecting resources manually increase with utility size as more resource combinations are required. Of the utilities reviewed, none with installed capacity greater than 4,000 MW used portfolio-based planning. BC Hydro's current situation, with a sizeable future load-resource potential gap and a variety of options to meet this gap, suggests that a scenario-based planning method may be more practical than a portfolio-based planning method.

2.3.1 Optimisation model

The recommendation to use a scenario-based planning method requires the use of a model for portfolio compilation. The model currently used by BC Hydro, System Optimizer, has been successfully used for the IRP process by Duke Energy [31], PacifiCorp [12], and Tennessee Valley Authority [16], among others. BC Hydro's current implementation of portfolio development, where up to 4,000 scenarios are used, is more comprehensive than the majority of scenario planning utilities reviewed, where the maximum number of scenarios studied was 106 by PacifiCorp [12]. There is no urgent recommendation to change models, as System Optimizer is used by many utilities in similar circumstances to BC Hydro, particularly Tennessee Valley Authority, which also has significant heritage assets and is government-owned. However, another program used for the same purpose is Strategist, from the same provider as System Optimizer. Where System Optimizer uses mixed-integer programming for its optimisation, Strategist uses dynamic programming, and may yield slightly different results. However, both System Optimizer and Strategist are deterministic models. System Optimizer solves a mixed integer optimisation problem and it can potentially be formulated as a stochastic mixed integer problem to address some of the uncertainties in the planning problem, but the problem becomes very difficult, if not even impossible, to solve. Strategist is a deterministic dynamic programming model which can potentially be extended to solve the stochastic optimisation problem.

We recommend that BC Hydro investigates the potential use of dynamic programming to solve the optimisation problem, as it could potentially be extended to address some of the uncertainties involved in long term capacity expansion problems. The inputs to System Optimizer for developing the portfolios are a price forecast, a load forecast, a resource inventory, and an inflow sequence. The development of these inputs is discussed further in the following sections.

Each System Optimizer "run" uses a single scenario made up of a selection of components. The full complement of options used by BC Hydro can be seen in Figure 2.1, where the highlighted boxes are the selections for a particular scenario run. In each run, BC Hydro can select and build scenarios under three main categories: uncertainties considered; resource choices; and modelling assumptions and parameters. Under the uncertainties considered, BC Hydro varies market price, load forecast, DSM deliverability, and additional load from LNG development in the north of the province. Under resource choices, they can vary usage of the 7% non-clean threshold, DSM options, and Site C (all units in) timing. Under modelling assumptions and parameters they can vary BCH/IPP cost of capital, use of pumped storage as a resource option, Site C capital cost, capital cost for alternatives to Site C, and wind integration cost in dollars per megawatt hour.

Modelling Map					
Uncertainties/Scenarios					
Market Prices	Scenario 2 Low	Scenario 1 Mid	Scenario 3 High		
Load Forecast	Low	Mid	High		
DSM deliverability	Low	Mid	High		
LNG Load Scenarios	Prior to Expected LNG	800 GWh	3000 GWh	6600 GWh	
Resource choices					
Usage of 7% non-clean	Yes	No			
DSM Options	DSM Option 1	DSM Target/ Option 2	DSM Option 3		
Site C (all units in) timing	F2024	F2026	No Site C		
Modelling Assumptions and Parameters					
BCH/IPP Cost of Capital	5/7	5/6			
Pumped Storage as Option	Yes	No			
Site C Capital Cost	Base minus 10%	Base	Base plus 10%	Base plus 15%	Base plus 30%
Capital Cost for alternatives to Site C	Base	Base plus 30%			
Wind Integration Cost	$5/MWh	$10/MWh	$15/MWh		
	shows the modeling assumptions				

Figure 2.1: Scenario variables and their potential values in BC Hydro's 2013 IRP

For each scenario, the System Optimizer model selects resources to minimise the overall cost of the resource in that set of conditions. This produces one portfolio of resources with a cost value. The uncertainty in this analysis lies in how accurately the scenarios reflect reality over time. Ideally a utility could run as many different scenarios as they required to capture all aspects of uncertainty, but in practical terms the maximum is usually in the thousands because of time and computing constraints. A portfolio output from System Optimizer contains: list of resources; in-service date; resource type; resource location; installed and dependable capacity; firm and total energy; net present value of generation and transmission resource costs, trade revenue, DSM option, and total portfolio cost; transmission expansion; and simulated generation and load.

Load forecast

Load forecast is obtained by aggregation of residential, commercial, and industrial loads. Residential and commercial loads are obtained from Statistically Adjusted End-Use (SAE) models using both economic variables (disposable income, population, retail sales, employment) and non-economic variables (weather, average stock efficiency of various end uses of electricity). Industrial loads are either developed for specific sub-sectors — for example pulp mills or mining — in consultation with the major customers in these industries, or developed from GDP growth projections.

Load forecasts contain uncertainties related to the variables used in their derivation. For example, if economic growth stagnates, energy demand tends to decrease, while a boom in an energy-intensive industry like liquid natural gas could significantly increase energy demand. Because of this, utilities often run simulations with multiple load forecasts, developing these through having different assumptions about economic and population growth, fuel availability, energy prices, etc. BC Hydro plans to the average load forecast, as per BCUC-approved policy [30].

Energy price forecast

The energy price forecast is used to assess trade revenues and benefits and is developed using several factors:

- Cost of new resources

- Gas price
- Modelling of WECC loads and resources
- Forward market

Of these four inputs, gas price and forward market are external forecasts, not developed by BC Hydro. The gas price is obtained from the New York Mercantile Exchange (NYMEX)forecasts, while PowerEx provides the forward market prices and forecasts. Modelling of WECC loads and resources is carried out by the Price Forecast team using a production costing model [30]. These are models that capture the operational costs of a generation fleet and minimise costs while dispatching the system under various constraints [32]. This model takes as inputs the plans of the WECC utilities for new generation and each jurisdiction's load forecast, and dispatches the planned resources to minimise the cost of energy. The price forecast obtained from this analysis is then used for developing projected market forecasts and scenarios. For example, different energy prices might be obtained from the production cost model by running low, medium, and high gas price forecasts.

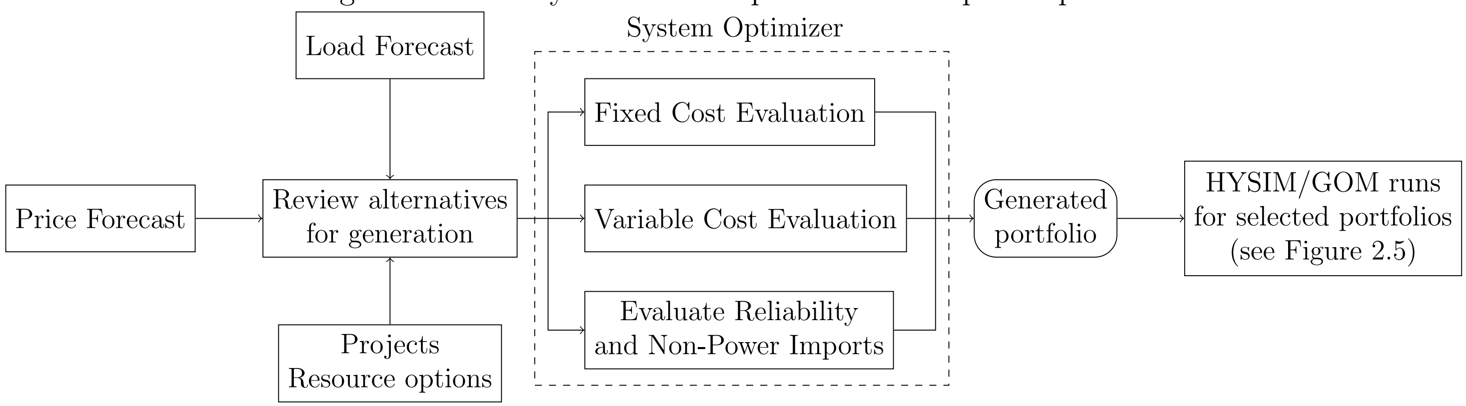
Resource inventory

The resource inventory consists of all existing resources in the current system plus any potential resources that the utility is considering including in a particular portfolio. For each resource, the information included is capacity, energy, average price of energy in dollars per megawatt hour, and location of resource. The resource inventory does not change between scenarios, unlike the other inputs, which can be altered to produce different scenario-portfolio pairs.

Inflows

BC Hydro uses 60 years of historic inflow data to calculate an average system operation for planning purposes. This takes into account plant constraints, non-power constraints such as environmental releases, and seasonal variations. While using real data means that the average is a good representation of the previous 60 years of inflow conditions, it also implies an assumption of stationarity that may not hold over future planning periods due to factors such as climate change. Firm energy is determined by dispatching the system in the lowest inflow years on record and calculating the energy produced under such critical conditions.

Figure 2.2: BC Hydro's current portfolio development process



2.4 Alternatives for portfolio construction

Dynamic programming (DP) is an alternative way to optimise portfolio selection. This modelling method works backwards from a given end state to determine the optimal intermediate states and thus the overall optimal path, using Bellman's principle of optimality, which states "An optimal policy has the property that whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision"[33].

DP is usually called a multi-stage decision-making process. Instead of deciding on all decision variables in one single optimization procedure, the DP procedure dynamically divides the problem into many smaller decision problems (e.g., optimal portfolio choice), one for each possible discrete state in each stage in a planning process and the problem is iteratively and sequentially solved to find the optimal solution or in the case of capacity expansion problems, the optimal investment strategy [33].

A general outline of a planning method using dynamic programming instead of mixed integer programming is shown in Figure 2.3. Resource combinations are constructed to cover all potential combinations of resources. For example, if a utility had five resource options that it wanted to optimise, the five portfolios constructed would be as shown in Table 2.1. The example is not intended to show all possible combinations, merely how a dynamic programming model would move between states (i.e. portfolios) in its optimisation.

Each of these portfolios would be initially simulated using HYSIM/GOM to obtain the costs and benefits of portfolio. Dynamic programming would then be used to choose, at each time step in the planning period, which state – i.e. portfolio – would be optimal. Figure 2.4 provides an example of the set up for a dynamic programming problem, in which each state is a particular portfolio, each stage is a time step between the present and the planning horizon, and the nodes represent decisions to implement a particular

Table 2.1: The portfolio construction scheme for dynamic programming

Portfolio	Resources
1	A
2	A, B
3	B, C
4	A, B, C, D
5	A, C, D, E
6	etc...

portfolio at that stage.

The advantages of using dynamic programming are that the benefits of each portfolio, not just the per unit cost of energy and of construction, are incorporated into the optimisation and resource selection without the need for multiple feedback loops through HYSIM and GOM. The disadvantage is significant simulation time because of the HYSIM/GOM runs needed to obtain operational costs and benefits for each portfolio with its particular resource combination. In addition, BC Hydro would be required to obtain a different model for this type of optimisation, as System Optimizer is a mixed-integer model and incapable of dynamic programming. Two dynamic programming models that have been used recently by utilities are Strategist (Public Service Company of Colorado [13], Arizona Public Service[5]) and PowerSimm (NorthWestern Energy[34]). The technical details of these models are not published and therefore their advantages and disadvantages cannot be fully assessed.

Figure 2.3: The IRP process using a dynamic programming model in place of System Optimizer

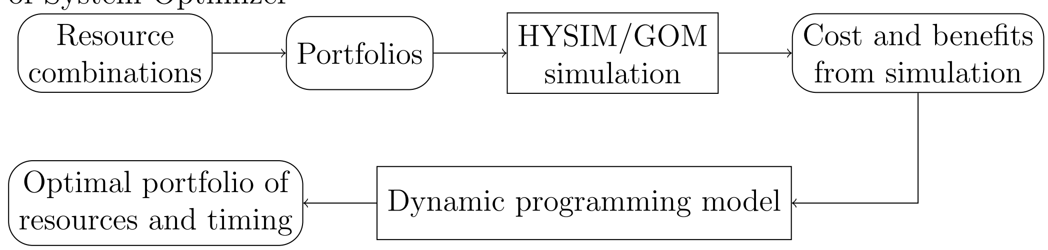
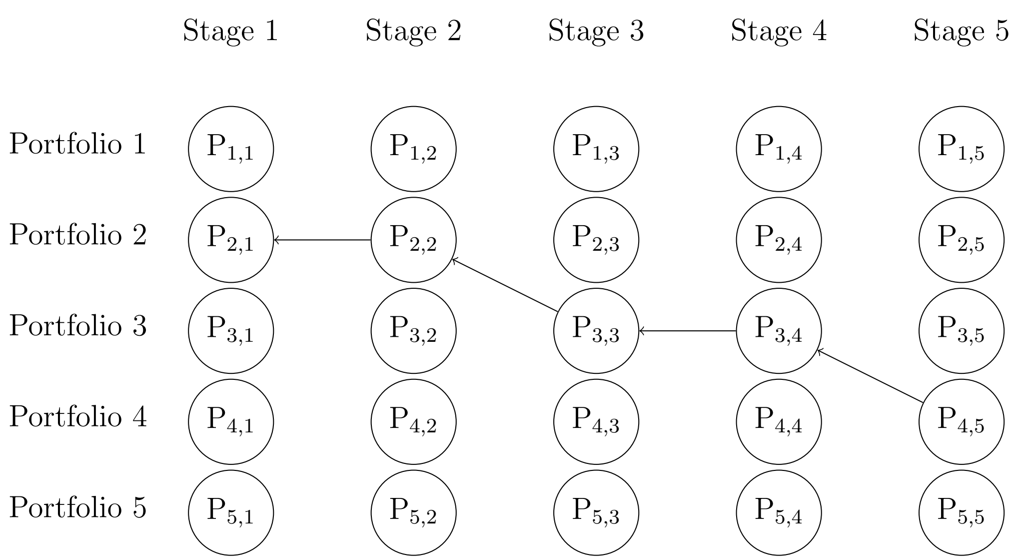


Figure 2.4: An example of dynamic programming selecting between various portfolios and optimising the overall resource selection



It is recommended that investigation of a prototype model of the capacity expansion problem for the BC Hydro system is considered. This could be formulated and solved using DP and Approximate DP in two phases. Using the BC Hydro System Optimizer inputs, Phase I would formulate and solve a deterministic DP capacity expansion problem for the BC Hydro system and the results will be compared to the currently used System Optimizer results. Phase II would formulate and solve the stochastic optimization problem using the data assembled in Phase I on capacity expansion portfolios and their stochastic state transitions given GOM run results for different scenarios of historic inflow sequences, market price and load forecasts.

2.5 Portfolio testing

Once a portfolio is built, a utility can use it “as is” or carry out further testing on the portfolio. It should be remembered that a portfolio developed through the aforementioned process is a portfolio optimised for a particular scenario. While this scenario may accurately reflect a particular future, it does not guarantee that the portfolio is optimal in a different future. All of the utilities studied in the previous review that used scenario-based planning conducted some further analysis on their most promising portfolios. This report recommends an approach in which a portfolio is subjected to a range of scenarios to simulate its performance rather than ending the analysis after the portfolio generation. This is often called sensitivity testing and was found to be part of the IRP processes of Arizona Public Service [5], Avista Corp[35], Duke Energy Indiana[31], PacifiCorp[12], Public Service Company of Colorado[13], and Tennessee Valley Authority[16]. This is somewhat akin to the analysis that occurs in portfolio-based planning once a portfolio has been selected. Idaho Power provides an excellent example of this process, where, once their portfolios have been manually compiled, the utility uses Aurora$^{\text{XMP}}$ to simulate the operation of the portfolio with different values of three underlying variables: natural gas price, load, and hydroelectric variablity. Probability distributions of these variables (normal or log-normal) were derived and Monte Carlo simulation used to randomly sample from these values for 100 iterations, resulting in 100 different costs for a particular portfolio. These values give an indication of the spread of the portfolio costs and therefore of the vulnerability of the portfolio to changes in underlying conditions (a proxy measure for risk).

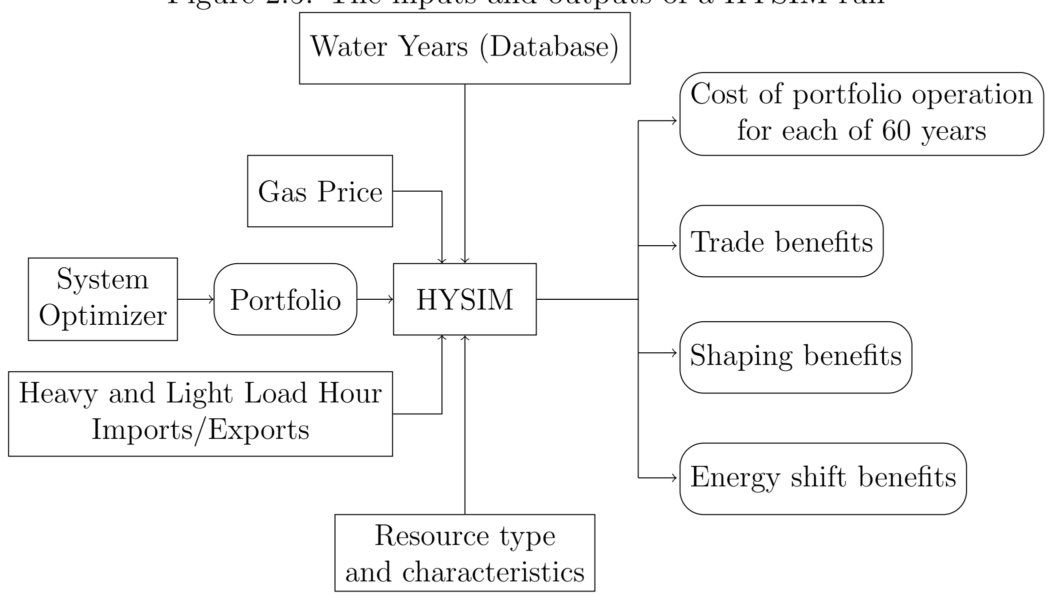
BC Hydro's current process simulates a portfolio's operation using the HYSIM and GOM models. Both HYSIM and GOM are deterministic models. Once System Optimizer has produced a portfolio, the information about resources and cost is entered into HYSIM. HYSIM then simulates the operation of the portfolio under each of sixty years of inflow data, attempting to avoid both shortages and spills and to maximise the value of BC Hydro resources. The end result of this analysis is a range of system operations and costs and benefits for the portfolio, corresponding to the sixty water years. In effect, HYSIM expands the single inflow forecast given to System Optimizer into sixty different forecasts and assesses the performance of the portfolio in each. HYSIM is currently run with an Excel-based spreadsheet interface. Inputs to HYSIM can be seen in Figure 2.5. The model runs on time steps of a month, or twelve time steps per year. Inputs to HYSIM can be seen in Figure 2.5.

BC Hydro then uses GOM for more detailed simulation of portfolios. GOM is an optimisation model programmed in the AMPL language. The model is run from a GUI linked to the shared HYSIM-GOM database, collectively called the Study Manager. GOM is used for outage cost studies, plant configuration studies, to test the costs of certain constraints on the system, and for "what if" studies with flows, costs, etc. As GOM is an optimizer, it solves all time steps simultaneously with perfect foresight, which may be overly optimistic. The combination of GOM using HYSIM outputs mitigates this tendency. GOM takes as inputs the outputs of HYSIM for monthly energy over all years in the planning period and the information from System Optimizer about the new resources. GOM optimises the timing and amount of importing and exporting energy, the dispatch of thermal resources, and where/when/how much water to store or use from BC Hydro's reservoirs. As HYSIM and GOM are used together, effectively working as a single step in the IRP process, the arguments for using HYSIM rather than a commercially available model apply equally to GOM.

The outputs from a GOM run are the feasible operational generation and reservoir pool schedule, and system and individual plant incremental costs, as well as the benefits that accrue to the system such as trade benefits from power import/export, shaping benefits, energy shift benefits, and flexibilty benefits. This gives a detailed picture of the actual operation of a portfolio generated by System Optimizer. This information can be used to refine a portfolio, and the process can loop back through System Optimizer, HYSIM, and GOM if needed.

For these runs with HYSIM and GOM, corporate market price forecasts are inflated/deflated to account for dry/wet years' inpacts on the Mid C market. This results in a range of costs for the different water years, giving an indication of the spread of the portfolio costs. However, inflows are not the only variable that is uncertain, and variables like load forecast and energy price can also be varied to assess the performance of the portfolio, based on the inputs to System Optimizer. The methods used in creating these forecasts are detailed in §2.3.1–§2.3.1. To generate alternative forecasts for sensitivity purposes, utilities may re-run their forecasting models with different assumptions, such as higher economic growth leading to increased demand, or with new sources of gas affecting market energy prices. Variation in inflows often comes from historical records of such data, and a utility may choose to run simulations with all years of a water record or with the highest, lowest, and average flows. Utilities may focus on scenarios that are probabilistically likely, looking for instance at the mean and the 30^{th} and 70^{th} percentiles of a

Figure 2.5: The inputs and outputs of a HYSIM run

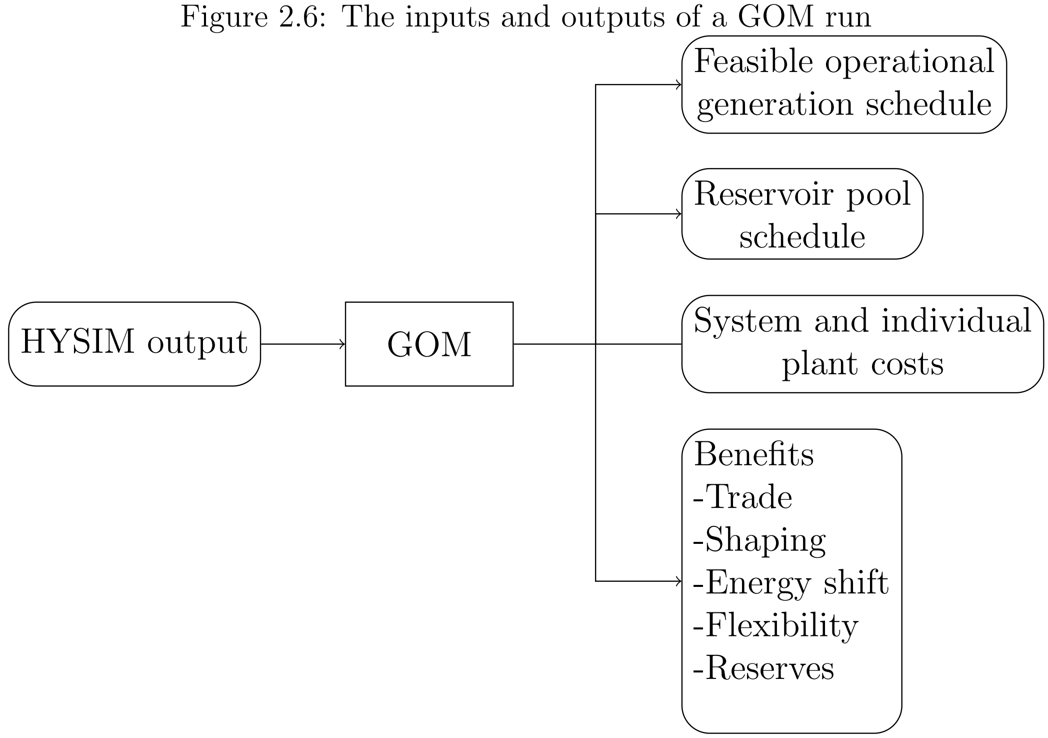


variable, or may consider the worst-case scenarios if they are particularly risk averse. BC Hydro's HYSIM/GOM model is capable of running this sort of simulation, and already does this for the different water years. Other models that could be used are Aurora$^{\text{XMP}}$ [6][35] or PowerSimm[34]. However, HYSIM is uniquely suited to BC Hydro's operations because of its capacity to model the Columbia River Treaty operations and how it values water in storage, particularly with BC Hydro's large reservoir facilities on the Peace and Columbia rivers. HYSIM is also an in-house model, whereas Aurora$^{\text{XMP}}$ and PowerSimm are commercial models requiring significant modifications and changes to model the BC Hydro system and will require the purchase of licenses and thus have higher costs.

2.6 Evaluation of model outputs

If portfolios are being simulated and tested to provide greater information to a utility's decision makers, some method of presenting this information in an

Figure 2.6: The inputs and outputs of a GOM run



easily useful form is required. The presentation of this information should especially facilitate and assist with comparison among portfolios. This requires the development, early in the planning process, of performance metrics. These depend on a utility's policies and objectives as well as their operating environment. Metrics for assessing portfolio performance can vary greatly depending on the objectives of the utility. The utilities studied in [29] used a variety of metrics to assess portfolio performance; observed were

- Mean cost [5][10][12][16]
- Standard deviation of costs [6] "Financial risk"[16]
- Tail VaR(85, 90, 95) [10][12]
- Fuel diversity [5]
- Water use [5]
- CO_2 emissions [5][12]
- Flexibility [16][13].

Each metric addresses a particular aspect of uncertainty. A summary of the recommended metrics is presented in Table 2.3 and discussed further in the following section.

2.6.1 Recommended metrics

The recommended metrics cover a range of uncertainties and provide a utility with a broader picture of the performance of their portfolio. Not all metrics are calculated from the same data. Mean portfolio cost, standard deviation of costs, and tail Value-at-Risk would all be calculated from the results of multiple HYSIM and GOM runs, where the portfolio is simulated with different values of underlying variables and a distribution of outcomes is generated.

CO_2 emissions would also be calculated from these simulation results, using equations to estimate the carbon emissions based on the capacity of thermal resources in the portfolio. Avoided carbon emissions can also be calculated based on the equivalent thermal resources that renewables displace. Portfolio resource diversity would be calculated using the direct outputs of System Optimizer which indicate the capacity and energy of each proposed resource and their percent contribution to the overall portfolio. Flexibility likewise would be calculated from the System Optimizer outputs of portfolio make-up, using different data depending on the choice of flexibility metric. The process of calculating the metrics is illustrated graphically in Figure 2.9, showing the inputs to the models, the models used, the outputs of the model, and the formulas needed to calculate the metrics from the data.

Expected value of cost

Mean cost is a common metric used to show the average cost of implementing a particular portfolio. This is calculated as

$$\mu = \frac{\sum_1^n \text{Portfolio cost}}{n}, \tag{2.1}$$

where n is the number of portfolio HYSIM/GOM simulation runs.

Standard deviation of cost

Standard deviation of costs shows how greatly the cost may vary and therefore what are reasonable contingencies to put in place. A smaller standard deviation of costs would indicate a portfolio that is stable across a wide variety of futures and therefore has a lower risk of exceeding cost thresholds. Standard deviation is calculated as

$$\sigma = \sqrt{\frac{\sum(x-\mu)^2}{N}}, \tag{2.2}$$

where x represents each value in the population (in this case, portfolio cost), μ is the mean value of the population, and N is the number of values in the population.

Tail value-at-risk of portfolio

Tail Value-at-Risk (TVaR) is calculated, like mean cost and standard deviation of cost, from the distribution generated by multiple HYSIM/GOM simulations of the portfolio. TVaR demonstrates the expected value of a loss given that an event outside a given probability level has occurred. Portfolios with lower TVaR values are therefore less risky. TVaR for a given percentile is calculated as

$$TVaR_{\alpha}(X) = E\left[-X|X \leq -VaR_{\alpha}(X)\right] = E\left[-X|X \leq x^{\alpha}\right], \qquad (2.3)$$

where X is the variable being considered (in this case, cost), x^{α} is the upper α-quantile given by $x^{\alpha} = \inf\{x \in R : Pr(X \leq x) \geq \alpha\}$, $|$ is the mathematical expression for "given", E is the symbol for expected value or average, and $\mathrm{VaR}_{\alpha}(\mathrm{X})$ is the the value-at-risk for a particular variable at a particular value of α.

Portfolio resource diversity

Resource diversity or resource mix suggests how vulnerable a portfolio will be to changes in fuel prices, as a system heavily dependent on one main resource will be significantly more vulnerable to changes in the price of that resource than a portfolio with a variety of generation options. A portfolio with a greater diversity of fuel sources would therefore be considered to have lower risk than one that relies heavily on a single resource. The variance of a portfolio, in the statistical sense of the term, could be a useful measure of the spread of the portfolio's resource distribution, and is calculated by

$$\sigma^2 = \frac{1}{n}\sum_{i=1}^{n}(x_i - \mu)^2 \tag{2.4}$$

where μ is the expected value of the capacity of all resources in the portfolio (see Equation 2.1) and x_i is the capacity of an individual resource. As the variance indicates the average of the spread of the variables about the mean, a low value of variance indicates that the energy generation is spread relatively evenly among the various generation options. A high value of variance indicates that a few of the resources are dominating the resource mix. The following example uses a portfolio from BC Hydro's 2013 IRP to illustrate the calculations (see Figure 2.7 and Figure 2.8).

The total firm capacity for each resource is used for this variance calculation. Any of the totals, either installed/firm capacity/energy could be used.
The variance calculations would be repeated for multiple portfolios and the results compared to determine the most diverse portfolio.

Water consumption

Water use was only a metric for Arizona Public Service, which operates in a region of scarce water resources and therefore has an interest in choosing generation that does not rely on heavy water usage. This metric could be calculated by historical water usage of a similar sized plant and by interpolation. A high water use would be undesirable. This metric is not of great value for BC Hydro given that their calculations already consider the value of water stored in their dams and optimise to use this as efficiently as possible.

Carbon emissions

CO_2 emissions was used as a metric by many utilities concerned about new regulation that would put a price on carbon emissions, affecting the dollar per MWh ratio of a high-CO_2 emitting resource and therefore portfolio make-up.

Figure 2.7: A BC Hydro portfolio

UECs and **UCCs** are shown for energy and capacity resource respectively. The UEC/UCC shown includes wind integration costs, soft costs and network upgrade costs where applicable. The UECs for gas-fired generation resources (CCGTs) are not shown as the UEC varies from year to year depending on the forecasted natural gas price.

Resources Selected

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2023	BCH_PR	Site C	1100	1,100	5,100	5,100	79
2028	BCH_PR	GMS Units 1-5 Cap Increase	220	220			35
2029	BCH_LM	MSW2_LM	25	24	208	208	92
2030	BCH_REV	Revelstoke Unit 6	500	488	26	26	50
2032	BCH_LM	Pumped_Storage_LM	1000	1,000			126
2033	BCH_PR	Wind_PC21	99	26	371	371	112
2033	BCH_PR	Wind_PC28	153	40	591	591	111
2034	BCH_PR	Wind_PC13	135	35	541	541	113
2034	BCH_PR	Wind_PC16	99	26	377	377	116
2034	BCH_PR	Wind_PC19	117	30	441	441	113
2035	BCH_PR	Wind_PC10	297	77	1,023	1,023	118
2036	BCH_VI	MSW1_VI	12	12	100	100	127
2036	BCH_VI	Biomass_VI	30	30	239	239	142
2036	BCH_LM	Run of River LM 80_100	62	10	174	223	108
2037	BCH_PR	Wind_PC09	207	54	713	713	122
2037	BCH_PR	Wind_PC15	108	28	382	382	119
2037	BCH_PR	Biomass_PR	28	28	223	223	141
2037	BCH_LM	Biomass_LM	30	30	239	239	143
2038	BCH_PR	Wind_PC14	144	37	527	527	117
2038	BCH_PR	Wind_PC20	159	41	610	610	119
2038	BCH_LM	Pumped_Storage_LM	1000	1,000			126
2039	BCH_PR	Wind_PC11	126	33	473	473	122
2039	BCH_PR	Wind_PC41	45	12	155	155	122
2039	BCH_PR	Wind_PC42	63	16	219	219	122
2040	BCH_PR	Wind_PC18	138	36	486	486	123
2040	BCH_VI	Wind_VI14	35	9	114	114	135

Figure 2.8: Total capacity for each resource in the IRP over the planning period

Supply Totals through 2020

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	0	0	0
Firm Energy (GWh)	0	0	0	0	0

Supply Totals through 2030

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	25	1,100	1,125
Firm Energy (GWh)	0	0	211	5,103	5,314

Supply Totals through 2040

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	500	10	2,125	1,100	3,735
Firm Energy (GWh)	7,026	175	1,014	5,103	13,319

Emissions avoided could also be calculated, based on the carbon emissions from a thermal resource of equivalent capacity. If utilities are concerned about the price on carbon, a portfolio with a lower level of carbon emission will be of lower risk. The volume of carbon emissions would be an output of the portfolio simulation process, and direct comparison between portfolios would be possible. If there are a range of carbon emissions for each portfolio due to the simulation process, then measures like the mean and the standard deviation can also be use for this analysis.

Flexibility

Flexibility was used as a metric by utilities that were interested in integrating higher levels of renewable energy from intermittent resources such as wind. As an illustration, the Public Service Company of Colorado was considering the addition of 1,200 MW of wind energy to their system in their 2011 IRP and therefore was interested in adding resources that could manage with variability, e.g. natural gas. Higher levels of flexible resources in a portfolio would indicate lower risk of the utility having shortfalls in capacity. Several metrics for measuring flexibility have been proposed in literature [36]:

- Percent of GW of installed capacity capable of load-following relative to peak demand,
- Systems where power area size, grid strength, interconnection (transmission), and number of power markets are given scores and combined into an overall flexibility score,
- Maximum upward or downward change in load that the system is capable of managing in a given time period from a given initial operational state, and
- Expected percentage of incidents in a given time period where the system cannot cope with the changes in net load.

The complexity of the calculations increases going down the list, and as BC Hydro already has significant ability to buffer renewables due to their large hydro resources, perhaps a relatively simple metric such as the first one listed would be sufficient.

An example of a flexibility calculation follows, using the portfolio in Figure 2.7 and Figure 2.8. In this case, all resources that do not contribute to flexibility, such as wind and run-of-river which actually reduce flexibility, are assigned a negative value equivalent to 5% of the installed capacity. For the resources that do contribute to flexibility, pumped storage is assigned a contribution of twice its installed capacity because of its ability to buffer with both capacity and pumping speed, and Site C is assumed to be able to contribute 25% of its installed capacity to flexibility. The flexibility values for each resource in this portfolio are therefore illustrated in Table 2.2. The peak energy demand expected in the 2013 IRP was 14,500 MW, thus using the first of the flexibility formulas listed above, the flexibility of this portfolio is

$$\text{Flexibility} = \frac{\text{Installed capacity (MW)} \times \text{multiplier}}{\text{Peak demand (MW)}} = \frac{4,889.4}{14,500} = 0.337$$

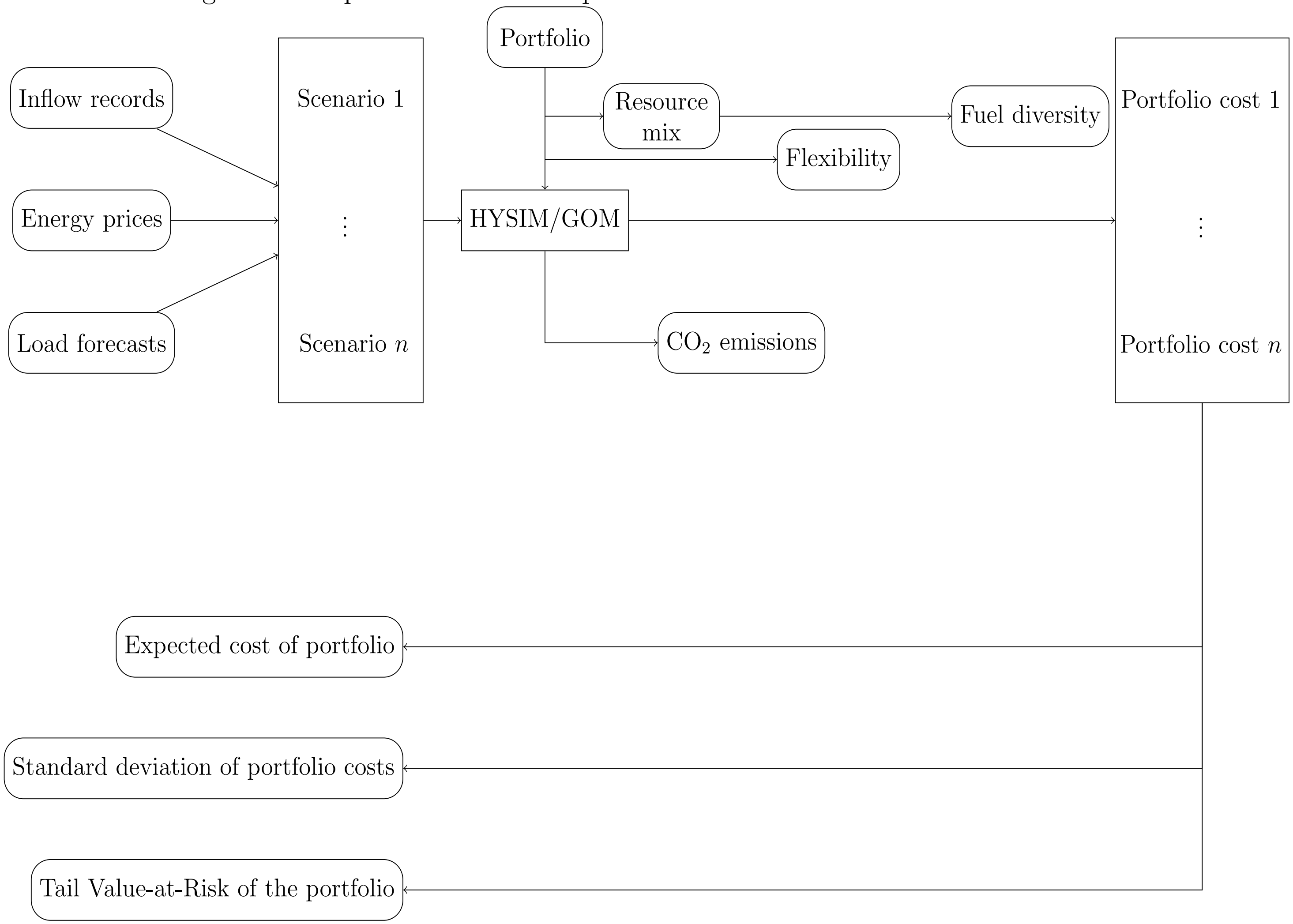
Table 2.2: Capacity of each resource in a portfolio multiplied by the appropriate multiplier for use in flexibility calculations

Resource	Installed Capacity (MW)	Flexibility Contribution
Site C	1100	275
GMS units 1-5 Cap Increase	220	220
MSW2_LM	25	-1.25
Revelstoke Unit 6	500	500
Pumped_Storage_LM	1000	2000
Wind_PC21	99	-4.95
Wind_PC28	153	-7.65
Wind_PC13	135	-6.75
Wind_PC16	99	-4.95
Wind_PC19	117	-5.85
Wind_PC10	297	-14.85
MSW1_VI	12	-0.6
Biomass_VI	30	-1.5
Run of River LM 80_100	62	-3.1
Wind_PC09	207	-10.35
Wind_PC15	108	-5.4
Biomass_PR	28	-1.4
Biomass_LM	30	-1.5
Wind_PC14	144	-7.2
Wind_PC20	159	-7.95
Pumped_Storage_LM	1000	2000
Wind_PC11	126	-6.3
Wind_PC41	45	-2.25
Wind_PC42	63	-3.15
Wind_PC18	138	-6.9
Wind_VI14	35	-1.75
Total		4889.4

Table 2.3: Summary of recommended metrics for portfolio comparison

Metric	Logic for inclusion	Measure
Mean	Provides the most likely cost, GHG emission level, water use, etc. of a portfolio	Arithmetic mean
Statistical dispersion	Shows how stretched or squeezed the distribution of a chosen portfolio characteristic is, and therefore is a measure of risk	Standard deviation, variance, interquartile range
Expected value of loss (or gain) if an event outside a given level of probability occurs	Shows average cost of the highest 10 percent of cases, measure of financial risk	Tail Value at Risk or Value at Risk
Diversity of portfolio resources	Indicates reduced vulnerability of portfolio to swings in single fuel price	Variance, possibly calculated from resource capacity in MW
Carbon emissions	For regulatory purposes due to the province's green/clean/renewable energy mandates	Tons of CO_2 per MWh
Flexibility	Gives an indication of how easily the system can deal with fluctuations from intermittent resources	Percent of total capacity able to buffer intermittent load relative to peak demand

Figure 2.9: Inputs and models required to calculate the recommended metrics



2.6.2 Scorecards

Metrics can be combined into scorecards for comparing portfolios. For example, each portfolio could be ranked from n to 1, where n is the number of portfolios being tested, for each separate metric. This would result in each portfolio having a score reflecting their relative merit among the portfolios as a whole.

Consider the case of a utility comparing three portfolios: A, B, and C. Each of these will be compared with four different metrics: expected cost, standard deviation of costs, fuel diversity, and tons of CO_2 emitted. Based on the values calculated for each of the metrics in Table 2.4, each portfolio can be given a ranking out of three for each metric (Table 2.5). This analysis would show that portfolio A performed most strongly when considered across all the metrics.

Table 2.4: Example of a scorecard for comparing portfolios using metrics and calculations

Portfolio	Expected cost	Standard deviation	Fuel diversity	CO_2 emissions
Unit	Millions	Millions	Statistical variance	Total tons CO_2
A	30	5	189	100
B	25	4	589	500
C	40	3	322	400

Table 2.5: Example of a scorecard for comparing portfolios using metrics, with the metric rankings instead of the calculated numbers

Portfolio	Mean cost	Standard deviation	Fuel diversity	CO_2 emissions	Total
A	2	3	1	1	7
B	1	2	3	3	9
C	3	1	2	2	8

Table 2.6: Example of a score card using weights to reflect utility priorities among metrics

Weights	40%	30%	10%	20%	
Portfolio	Mean cost	Standard deviation	Fuel diversity	CO_2 emissions	Total
A	0.8	0.9	0.1	0.2	2.0
B	0.4	0.6	0.3	0.6	1.9
C	1.2	0.3	0.2	0.4	2.1

If a utility was very concerned about a particular metric, they could apply a multiplier to ensure that metric carries greater weight in the analysis. For example, the utility could rank their metrics in order of importance – 1) mean cost, 2) CO_4 emissions, 3) standard deviation of costs, and 4) fuel diversity – and give each of these a weight such that the total adds up to 100 percent (see Table 2.6). This can result in significantly different relative rankings for portfolios, as in this case portfolio B is the best performing.

This report recommends the introduction of a system of metrics and scorecards for BC Hydro's uncertainty management and portfolio testing. Of the various metrics identified in the jurisdictional review, several could be relevant to BC Hydro and are detailed in Table 2.3. These provide a broad picture of a portfolio's characteristics. The disadvantage of this approach is that more work is necessary to carry out the analysis and interpret the data. The advantages are easy comparison of portfolios and a transparent process for ranking, assisting with both decision-making and justification of decisions to the public and regulatory bodies. The alternative is to have a single criterion for choosing a portfolio, such as mean cost. However, use of a single criterion does not take into consideration the risk of a portfolio being more costly, its environmental impacts, or any other factors that may affect the success of the portfolio's implementation.

2.6.3 Trade-off analysis

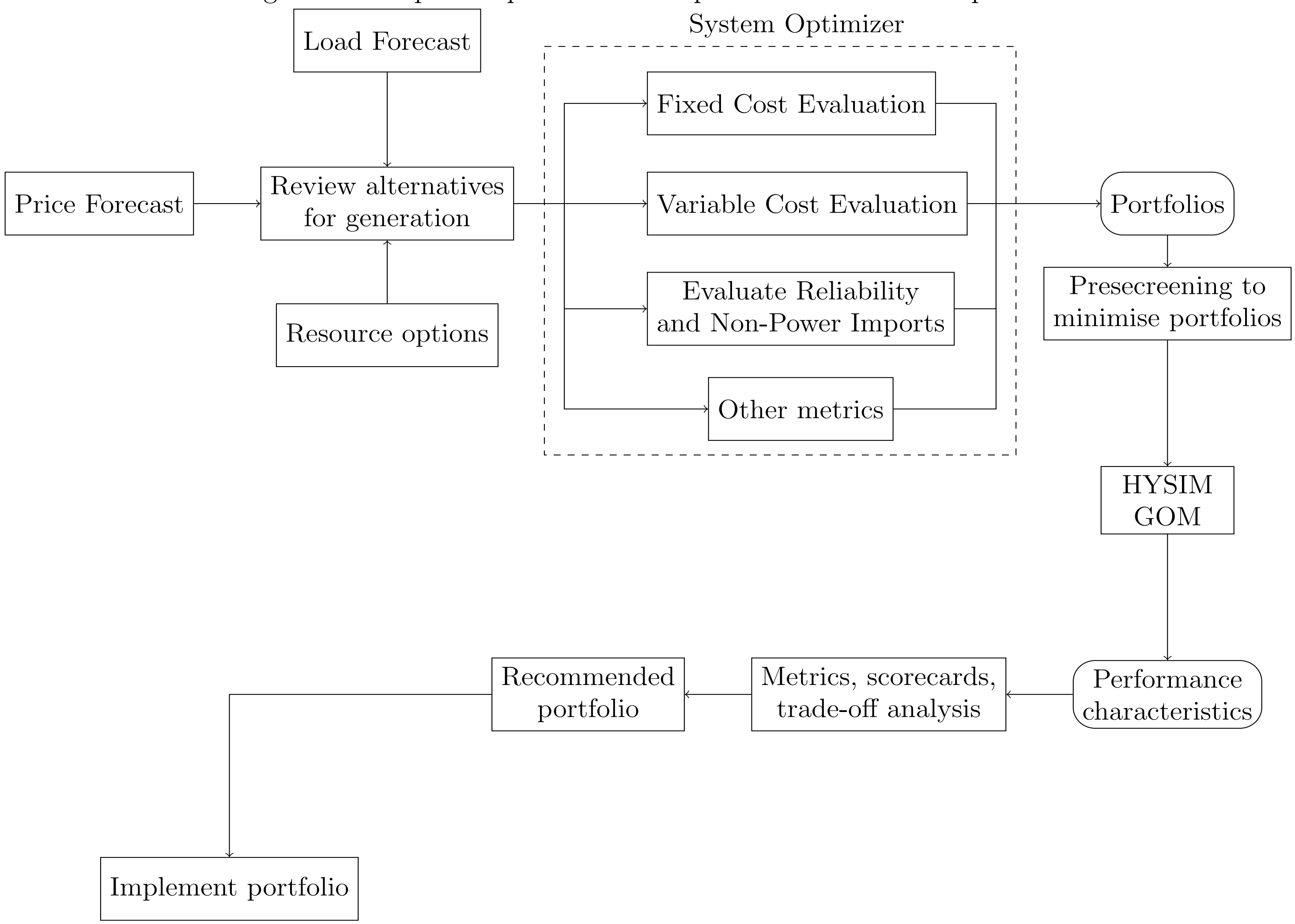
Metrics can also be useful for direct trade-offs between two performance characteristics of one portfolio at a time. If for instance a utility is interested comparing portfolio mean cost to level of risk, they can plot mean cost against a measure of risk (say standard deviation of costs or TVaR) and find the lowest-cost portfolio for a given level of risk i.e. the "efficient frontier", trading off between the two metrics. In addition, this sort of plot would allow a utility to observe incremental cost changes to obtain a lower or higher level of risk. This is the approach advocated by the Northwest Power and

Conservation Council in their sixth regional power plan [10]. This report recommends the use of this method for BC Hydro in cases where two metrics appear to be inversely related, such as fuel diversity and mean cost. A comparison between mean cost and TVaR or standard deviation can also be considered. While the disadvantage of this approach is increased manipulation of the data, the advantages for decision-making are significant: direct comparison between contradictory metrics and ease of identification of the "best" portfolios under consideration.

2.7 Summary and conclusion

- Continue to use the current capacity expansion model (System Optimizer) for developing portfolios from multiple scenarios
- Investigate the potential use of dynamic programming for portfolio selection and compare its output with that of System Optimizer
- Use HYSIM/GOM for further sensitivity analysis of individual portfolios, expanding beyond the 60 water years and expanding to include alternative loads, gas prices, and energy prices
- Develop metrics and scorecards and/or efficient frontier analysis for assessing portfolio performance
- Develop a GUI for running HYSIM to streamline the process of running the increased number of simulations. This can be done by enhancing the existing GOM GUI.

Figure 2.10: Updated portfolio development and assessment process



Chapter 3

Practical methods of considering uncertainty in integrated resource planning for hydropower systems

This chapter was written as a manuscript for publication in a journal related to electric planning or energy policy. References in cited in this chapter can be found in the Bibliography section of the thesis. Some sections within the document have been moved for clarity. Section 3.2.7 is a modified version of section 2.6.1 from Chapter 2.

3.1 Introduction

Electric energy utilities face a variety uncertainties when engaging in long term capacity expansion planning. These include uncertainties such as future demand, prices for fuels such as gas and coal, new regulations restricting or prohibiting fossil fuel generation, regulations governing carbon pricing and green house gas emissions, level of subscription to demand reduction scheme and effectiveness of energy efficiency programs, flexibility required to integrate higher levels of intermittent renewable resources, resource availability (gas, water, coal, etc.) and so on. Some of these uncertainties have become more prominent in the last few decades, particularly those around renewable resource supply and pricing. Utilities desiring to reduce their susceptibility to risk therefore have to incorporate in their planning some method of assessing the impacts and mitigating the effects of these uncertainties. This paper investigates the current practice of electric energy planning among utilities in the United States and Canada. This work focused on achieving four objectives: (1) examine the various planning methods used by utilities in North America, (2) investigate how the planning processes handled uncertainty, (3) assess how circumstances prompted use of a particular planning method, and (4) develop and recommend a conceptual framework for treating uncertainty in IRP processes for large scale hydroelectric systems.

3.1.1 Structure of paper

This paper is organised in the following manner. Section 3.2 presents the uncertainties facing utilities, the utility approaches to planning under uncertainty, commonalities and differences in the planning methods identified, the modelling methods and programs used, and the introduction of metrics and scorecards as assessment criteria for rating portfolio performance under uncertainty. Section 3.3 describes BC Hydro's system and operating environment and its current planning method, which is contrasted with the findings from Section 3.2. The development of a new framework for BC Hydro is outlined and recommendations for progression from the current regime to the new framework are presented. The conclusions and policy implications of preceding sections are then discussed in Section 3.4.

3.2 Literature review

IRP, defined as electricity planning that considers both supply-side and demand-side resources for inclusion in capacity expansion resource portfolios [37, 4], is practised by relatively few jurisdictions. Much of the United States either practices IRP or is returning to IRP processes after failure of competitive generation in deregulated markets [23, 3, 38]. Canada has a variety of planning systems, ranging from the deregulated Alberta Electric System Operator that carries out load forecasts and then sends out requests for offers, to the more vertically integrated British Columbia system where BC Hydro submits an IRP every five years to the British Columbia Utilities Commission [39, 30]. South Africa's national energy company, Eskom, instituted IRP planning in 2010 with the publication of their Integrated Resource Plan for Electricity 2010-2030 [1]. The state of Queensland in Australia can arguably be said to practise IRP because of its emphasis on load reduction – through demand-reduction and energy efficiency – to avoid extensive capital works necessary to supply a widely dispersed population [2]. Brazil's large electric system is beginning to consider energy efficiency (EE) but does not directly pit EE or demand-side management (DSM) as competitors against new generation and therefore cannot be said to carry out IRP [40]. This study therefore focused on the United States, where examples of IRP are plentiful, and on Canada.

The information necessary for this study was obtained from each utility's published integrated resource plan. These were available from the utility directly or from a state or province's public utilities commission. The utilities were chosen to provide a good coverage of resource mixes and regulatory processes in North America. Both east and west coast utilities were selected to allow for differences in climate and fuel mix used. The east coast, for example, had a higher reliance on nuclear energy [31, 16]and less capacity for solar than the west coast [5, 8, 12]. Differences in market structure and ownership (public or private) also influenced utility selection, such as PG&E as a private investor-owned utility providing contrast to the municipally owned LADWP. Each utility's plan was examined to identify the planning method used and the strategies used for managing uncertainties. Planning methods and uncertainty strategies that recurred frequently among the utilities were analysed to discover the combination of factors that lead to the choice of planning method used.

3.2.1 Common uncertainties faced by utilities

From analysis of the utilities' published IRPs, some common uncertainties were discovered across the study. The main uncertainties were load growth, energy prices, and gas prices (as a significant driver of energy prices due to gas-fired generation acting as rapidly available generation in the event of a shortfall in capacity). Other common uncertainties were regulations and level of carbon pricing, effectiveness of demand-side management, and costs for renewable resources. Table 3.1 provides a breakdown of the uncertainties explicitly considered by each utility in the study. Some of these variables have historical data that allow a utility to make educated assumptions about their variabilities and potential values. Others like carbon pricing and effectiveness of demand-side management are more difficult to predict because of lack of historical precedents. However, historical precedents do not guarantee continuation of these trends in the future, as the changes in gas prices with the development of shale gas in North America has illustrated. Recent research considers methods of quantifying the economic value of DSM to reduce this uncertainty [41].

The common approach to uncertainty management among the utilities involved building scenarios with differing values of the uncertainties considered. This translates into utilities with high concern about gas prices developing scenarios with five different gas prices. Utilities concerned about changes in load would likewise produce scenarios with several different values of load and simulate the performance of their system under each of these scenarios.

Some utilities chose to use aggressive values of a variable to produce worst-case scenarios and plan and prepare accordingly. Others decided to eliminate their exposure to a particular risk completely, for example by divesting from all coal-fired generation in an attempt to remove uncertainty around carbon prices and emission regulations.

3.2.2 Utility approaches to planning under uncertainty

Utilities appeared to use one of two main methods for managing their planning under uncertainty. In one method, which we will call portfolio-based planning or portfolio planning, the utility builds a portfolio which they then test under uncertainty. In the second method, which we will call scenario-based planning or scenario planning, the utility builds scenarios that cover a range of uncertain futures and then build portfolios expected to perform well in these futures. Table 3.2

Utilities also considered uncertainty in the length of their planning horizon and the frequency of plan updating. A plan to be executed over a short period would be more flexible and therefore more sensitive to uncertainty, but there is a trade off with stability and the length of time required for commissioning new resources. Most companies opted for a 20-year horizon, with exceptions among the Californian investor owned utilities ("IOUs") which chose 10 years. The frequency of plan updating also differed, ranging from two years to five years, with two years being most common. The utilities with updating periods longer than two years were BC Hydro, Tennessee Valley Authority, and the Northwest Power and Conservation Council [30, 16, 10]. Both BC Hydro and the Tennessee Valley Authority are government owned utilities (by the province of British Columbia and by the U.S. federal government, respectively) with significant owned generation assets, which perhaps provides the stability for updating less regularly. The Northwest Power and Conservation Council is an advisory body which considers the Pacific Northwest region as a whole and does not own any generation, thus it

Table 3.1: Uncertainties considered by the utilities

Utility	Load	Fuel prices (gas, coal)	Energy prices	Retirements (coal, nuclear, hydro)	GHG prices and penalties	Renewable energy regulation	Hydroelectric availability	PV or CHP uptake	DSM/EE uptake	Interest rate	Tax incentives	Electric vehicles	Imports	Transmission	Plant construction costs	Storage additions
APS	•	•		•	•	•			•	•	•	•				
Avista	•	•		•	•	•			•							
BC Hydro	•		•			•	•		•	•					•	
DEI	•	•		•	•	•				•						
Idaho Power	•	•		•	•	•			•							
LADWP		•		•	•			•			•					
NWPCC	•	•	•		•		•				•			•	•	
NWE																
PG&E	•			•				•	•				•			•
Pacificorp	•	•		•	•				•	•						
PSCC	•	•			•	•				•						
SDG&E	•			•				•	•				•			•
SCE	•			•				•	•				•			•
TPU	•	•		•	•	•	•		•		•	•				
TVA	•	•		•	•	•			•							

Table 3.2: Choice of planning process for studied utilities

Utility	Method		Planning horizon	Update period	Plan vintage
	Portfolio	Scenario	(years)	(years)	
APS		×	15	2	2014
Avista		×	20	20	2013
BC Hydro		×	20	5	2013
DEI		×	20	2	2013
Idado Power	×		20	2	2015
LADWP	×		20	2	2014
NWPCC	×		20	5	2010
NWE	×		20	2	2013
PG&E	×		10	2	2011
PacifiCorp		×	20	2	2013
PSCC		×	40	4	2011
SDG&E	×		10	2	2014
SCE	×		10	2	2011
TPU	×		15	2	2015
TVA		×	20	4	2015

has less urgency to update a plan for implementation than most operational utilities[10]. In addition, more frequent plans might not capture longer-term trends over the Pacific Northwest. The update periods chosen by utilities seem to be a balance between the need for stability in a long-term plan and the need for flexibility to meet uncertain futures.

3.2.3 Initial steps for both planning methods

A necessary initial step, even before determining the need for new resources, is the choice of performance metrics against which the portfolio performances will be measured. This assists in guiding the overall process, as it clarifies the utility's objectives. The assessment criteria can range from something as simple as picking the lowest-cost portfolio to more complex criteria balancing cost, risk, the regulatory environment, company direction, etc. To some extent, the choice of criteria reflects a utility's attitude to uncertainty, with more conservative utilities, typified by government-owned or crown corporations [16, 30], choosing to consider a wider range of criteria to mitigate a broad spectrum of risks, while private utilities may weight their analysis more heavily towards risks in costs.

To determine need for new resources, the utility must have a forecast of future load. Uncertainty in this aspect is high, as load growth is influenced by variables such as economic growth and population trends [17, 35], weather [35, 31], etc., all of which introduce uncertainty into the forecast. The utilities studied largely choose to use mean values of their underlying factors and produce a base-case most-likely forecast, mitigating uncertainty by also developing forecasts for higher and lower load levels [5, 31, 12] to show the potential variation in their load. All the utilities except Tacoma Power applied reserve margins to this forecast, ranging from an additional 10% up to 15%.

Once a estimate of future need has been determined, utilities may screen potential resource options for inclusion in portfolios. Uncertainty management in this step consists of avoiding resources with significant risks or requiring the inclusion of particular resources for risk management reasons. This may mean rejecting new/retiring old coal generation over concern about new regulatory controls on emissions, or requiring new gas generation for balancing the inclusion of wind due to renewable energy regulations.

3.2.4 Modelling

Both portfolio-based planning and scenario-based planning require the use of models to assist in simulating portfolio performance or assist in compiling portfolios for given scenarios. The most popular models used by portfolio-planning utilities in this study were the PowerSimm model and the Aurora$^{\text{XMP}}$ model. NorthWestern Energy used the PowerSimm model for their 2013 IRP modelling [34]. The model works in two general stages. First, PowerSimm builds simulations of future prices using regression relationships of energy supply and observed price patterns. The model attempts to keep relationships between weather, load, wind, hydro, market prices intact, to more accurately simulate future conditions. Distributions are assigned to each variable, and Monte Carlo simulation is carried out to produce random scenarios. The model then simulates the operation of the portfolios generating units over a particular scenario. The projections from the first step are fed into the operational module, which simulates hourly generation costs for the portfolios. The model then optimises the operation of the portfolio over the planning horizon by trying to minimise generation costs. Both Avista and Idaho Power used the Aurora$^{\text{XMP}}$ model, but for different purposes. Avista used the model to generate 500 scenarios by random sampling from sets of gas prices, loads, water years, thermal outages, and wind penetration levels [35]. The utility then used their internally developed PRiSM model to build optimal portfolios for each of the scenarios. Idaho Power instead used Aurora$^{\text{XMP}}$ for simulating the operation of their manually-compiled portfolios [6], in the same manner as NorthWestern Energy used PowerSimm.

For scenario-planning methods, once the scenarios are developed, they are input into the utility's optimisation model. The model will compile a portfolio, using the screened resource options, that is optimal according to the constraints given in the scenario. The utility must be very clear about their definition of "optimal", which follows from the development of the performance metrics identified earlier in the process. In some cases this is the lowest cost portfolio, while in others it is the least risky or the most stable portfolio. The models most commonly used were System Optimizer ("SO") and Strategist. Both models select optimal resource combinations for a particular input scenario, either using mixed integer or dynamic programming optimisation methods [30, 43]. An objective function describing the relationship between variables and the value to be optimised is developed, and the program run to minimise or maximise the objective function. PacifiCorp, Tennessee Valley Authority, Duke Energy, and BC Hydro all used SO in their IRP planning [12, 31, 16, 30], while Strategist was used by Arizona Public

Service and Public Service Company of Colorado [5, 13].

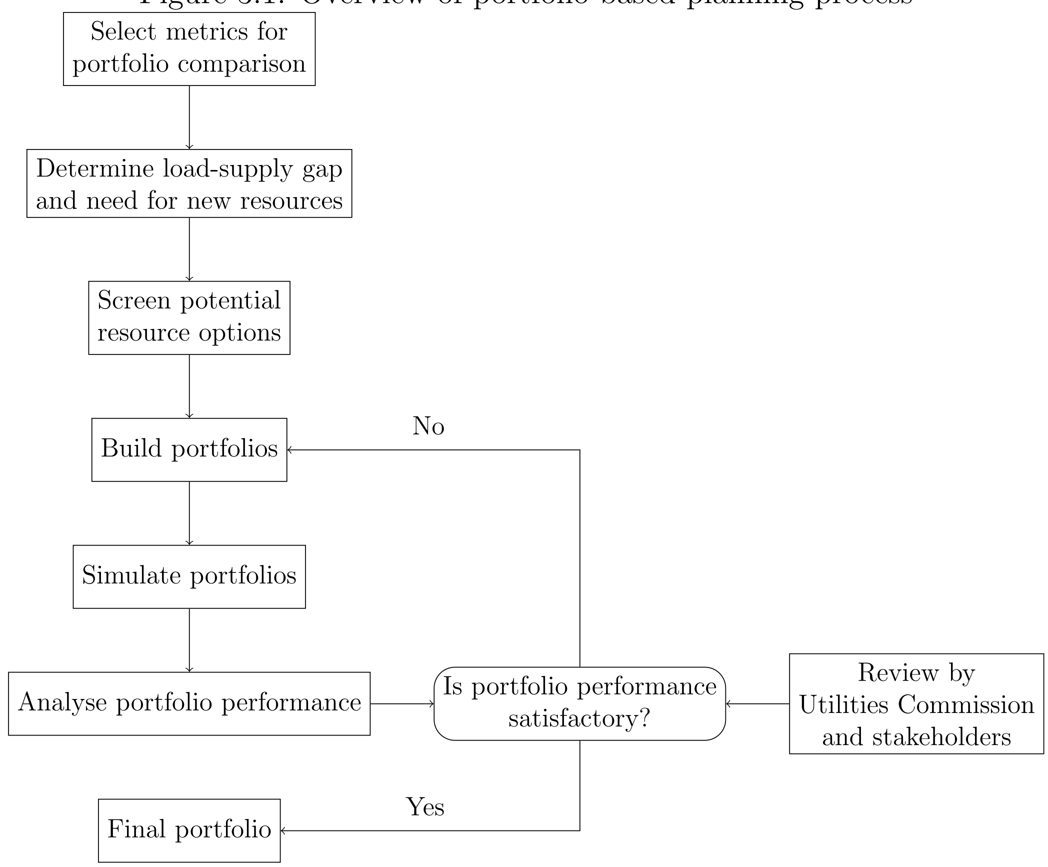
3.2.5 Portfolio-based planning

Portfolio planning is so called because a utility first develops their portfolios, manually, and then simulates the performance of the portfolios. The process is illustrated in Figure 3.1. There are advantages to this method, as a utility has direct control over which resources are selected and in what quantities. This works particularly well for utilities that have limited options for adding new generation and therefore have little difficulty in selecting combinations of resources. An illustration of this is available in the three largest IOUs in California: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. Californian regulations mandate that utilities must follow a particular "loading order" for meeting shortfalls in power supply, namely that shortfalls must be first met by energy efficiency and demand-side management, then by renewables, and lastly by efficient fossil fuels [19, 17]. Thus portfolio construction for these utilities is trivial.

The portfolio planning method is also effective for smaller utilities that do not need to select a large number of resources to fill their load-resource gap. An example of this was provided by Tacoma Power's 2015 IRP, in which the utility determined that all future growth in their planning period could be met by their current capacity and by energy efficiency and demand-side management measures [15]. However, the utility decided to conduct analysis on new resources in the event of unexpected changes to load and experimented with adding an additional 50 annual MW (aMW) of energy efficiency/demand-side management, wind, solar, combined cycle gas, Columbia River hydro purchase, or run-of-river hydro power purchase to their existing portfolio. This method was effective because Tacoma Power's low load growth allowed the energy gap to be filled by a single resource and made the portfolio comparison relatively simple.

Following on from the shared initial steps in Section 3.2.3, utility con-

Figure 3.1: Overview of portfolio-based planning process



structs their portfolio, manually choosing a combination of resources that satisfies the requirements for load. Uncertainty management at this step usually involves the utility constructing several different portfolios, with resource combinations that the utility is interested in or concerned about. Idaho Power for example developed 23 portfolios for their 2015 IRP, all featuring various levels of coal retirement because of uncertainty over Section 111(d) of the Clean Air Act [6]. Stakeholder consultation may be part of the portfolio development process, mitigating the risk of later disagreement over resource choices.

The utility then sets up the scenarios for simulating and optimising the dispatch of the portfolio. As the aim of the analysis is to stress underlying variables and observe the changes in portfolio performance, the utilities specify a range for each of their key variables and then use Monte Carlo simulation to select from these distributions and develop a random scenario. Idaho Power selected natural gas price, customer load, and hydroelectric variability as their stochastic variables, assigned distributions to each variable, and created 100 different scenarios consisting of random draws from the three distributions, resulting in a distribution of costs for each portfolio.

Finally, the utility uses the results from the simulation/optimisation to decide on a preferred portfolio, based on the performance criteria defined at the beginning of the process and in consultation regulators and stakeholders. If cost was the main criterion, then the portfolio that had the lowest average cost should be selected as the preferred portfolio. If minimising the range of net present value of total portfolio cost is the aim, then the utility would choose the portfolio with the lowest spread of costs. Idaho Power took the results of their 100 iterations and created graphs of portfolio cost versus exceedance probability, comparing the 95%, 50% and 5% exceedance probabilities for all portfolios, and graphs of standard deviation versus exceedance probability for all portfolios. Idaho Power also conducted tipping point analysis for two portfolios, one with a high penetration of PV solar and one with 300 MW of pumped hydro storage. The utility wanted to investigate the effect of variation in capital cost on the overall cost of the portfolios. By varying only the capital cost of the solar and of the pumped hydro, the utility could determine their preferred portfolio (from among the two in the tipping analysis) if the capital costs are known. Eventually, this combined analysis led to the choice of a preferred portfolio.

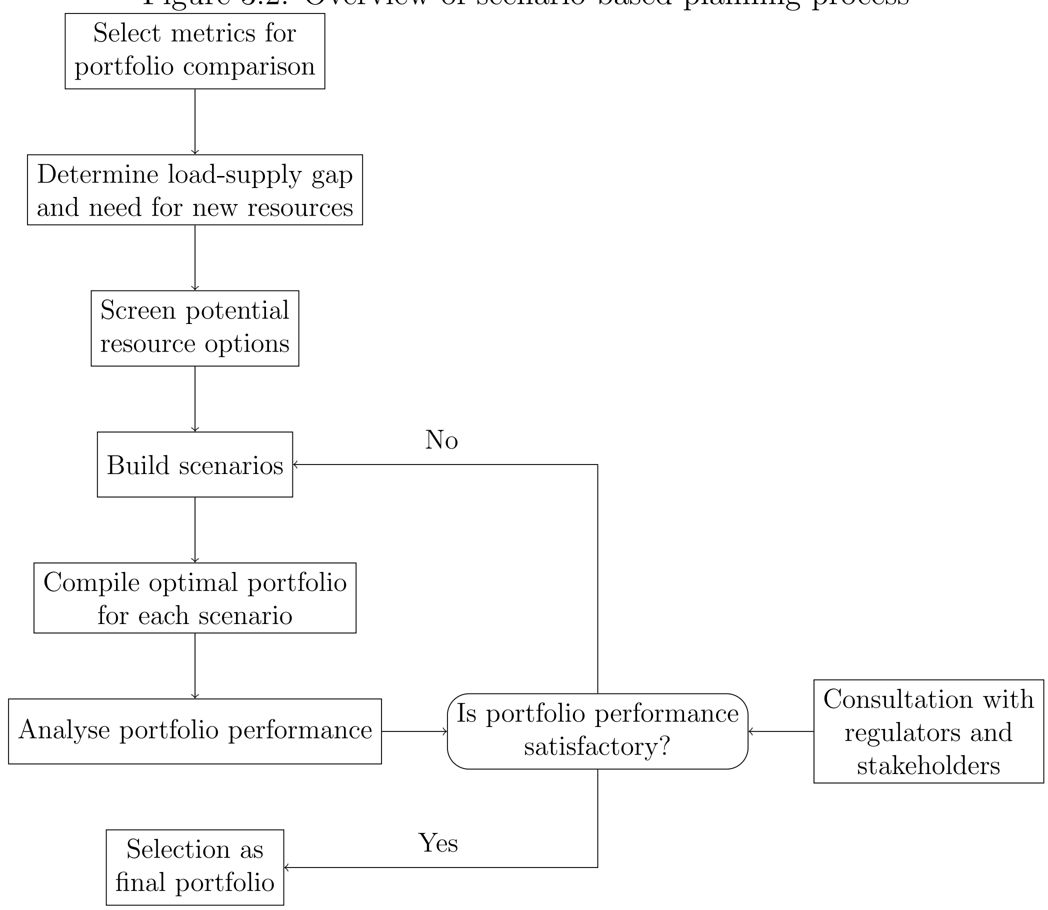
3.2.6 Scenario-based planning

Scenario planning involves a utility constructing combinations of futures and using an optimisation model to compile portfolios that are optimal in each scenario. An illustration would be a utility concerned about variation in gas prices and load in the future, which then constructs scenarios with combinations of high, medium, and low gas price, and high, medium, and low load, resulting in nine different scenarios for use over the planning horizon. Using an optimisation model, the utility would then set up their objective function to reflect the factors to be optimised, and would run the model to build portfolios for each scenario. The resulting portfolios are then assessed against performance metrics and the best performing one chosen as a preferred portfolio. Scenario planning has the advantage of not requiring manual portfolio compilation, which can be a difficult task in the case of large utilities with significant load-resource gaps. For example, Tennessee Valley Authority projected the energy gap in their 2015 IRP to range from 10,000 to 50,000 GWh over the planning horizon [16]. As it is unlikely a single resource could bridge an energy gap of this size, it becomes necessary to consider combinations of resources, thus making the analysis more complex.

Scenario planning shares several initial steps with portfolio planning, namely selecting metrics for portfolio assessment, determining the load-resource gap, and screening potential new resource additions. The process diverges from this point as shown in Figure 3.2.

Scenario development can occur at any point before modelling but com-

Figure 3.2: Overview of scenario-based planning process



monly occurs near the beginning of the process. The number of scenarios used can range from several [5, 31, 16]) to hundreds [12] or even thousands [30]. Utilities using fewer scenarios tended to be more deliberate in their scenario development, selecting disparate variable combinations to broaden the conditions covered. Utilities using tens or hundreds of scenarios had a more continuous spectrum of scenarios with fewer differences between combinations. In choosing the variables and values to go into the scenarios (e.g. high/low gas prices, carbon prices, energy prices, etc.), the utility is making decisions about the uncertainties of most concern to them and managing these by ensuring they are included in the simulation.

Once portfolios have been constructed for all scenarios, using an optimisation model as mentioned in Section 3.2.4, the utility will assess portfolio performance and decide if further testing is required. Using the metrics developed earlier, utilities can rate the performance of each portfolio and decide which portfolios are most promising. The choice of preferred portfolio can be made at this stage, or else a subset of the portfolios may be selected for further analysis such as sensitivity testing or Monte Carlo simulation to randomly sample from distributions for the underlying variables. Utilities can also look for trends in the resources chosen in the portfolios. If, for example, a resource option is selected in many portfolios, this may indicate a particularly stable/robust resource across a range of futures, and thus a good candidate for inclusion in the eventual preferred portfolio. To generate alternative forecasts for sensitivity purposes, utilities may re-run their forecasting models with different assumptions, such as higher economic growth leading to increased demand, or with new sources of gas affecting market energy prices. Variation in inflows often comes from historical records of such data, and a utility may choose to run simulations with all years of a water record or with the highest, lowest, and average flows. Utilities may focus on scenarios that are probabilistically likely, looking for instance at the mean and the 30^{th} and 70^{th} percentiles of a variable, or may consider the worst-case scenarios if they are particularly risk averse.

3.2.7 Assessment criteria for portfolios

Once a portfolio is built, a utility can use it "as is" or carry out further testing on the portfolio. It should be noted that a portfolio developed through the scenario planning process is a portfolio optimised for that particular scenario only and is not optimised over all potential realisations of the stochastic variables. Thus it is important to note that while this scenario may accurately reflect a particular future, it does not guarantee that the portfolio is optimal in a different future. In addition, the scenario is assumed to be constant for the entire planning horizon, thus the process is essentially the development of scenario trees for which optimal portfolios are developed. There is no ability to switch between different branches of the tree at any stage, as in dynamic programming. All of the utilities in the study that used scenario-based planning conducted some further analysis on their most promising portfolios. This is somewhat akin to the analysis that occurs in portfolio-based planning once a portfolio has been selected. Idaho Power provides an excellent example of this process, where, once their portfolios have been manually compiled, the utility uses Aurora$^{\text{XMP}}$ to simulate the operation of the portfolio with different values of three underlying variables: natural gas price, load, and hydroelectric variability. Probability distributions of these variables (normal or log-normal) were derived and Monte Carlo simulation used to randomly sample from these values for 100 iterations, resulting in 100 different costs for a particular portfolio. These values give an indication of the spread of the portfolio costs and therefore of the vulnerability of the portfolio to changes in underlying conditions (a proxy measure for risk).

Assessment of portfolio performance requires the development of performance metrics. These depend on a utility's policies and objectives as well as their operating environment. Metrics can vary greatly depending on the objectives of the utility. The utilities studied in the jurisdictional review used a variety of metrics to assess portfolio performance; observed were

- Mean cost [5, 10, 12, 16]
- Standard deviation of costs [6] or "Financial risk"[16]
- Tail VaR(85, 90, 95) [10, 12]
- Fuel diversity [5]
- Water use [5]
- CO_2 emissions [5, 12]
- Flexibility [16, 13].

Each metric addresses a particular aspect of uncertainty and provides the utility with slightly different information about their portfolio. Mean cost or expected value of cost is a common metric used to show the most likely cost of implementing a particular portfolio.

Standard deviation of costs shows how greatly the cost may vary and therefore what are reasonable contingencies to put in place. A smaller standard deviation of costs would indicate a portfolio that is stable across a wide variety of futures and therefore has a lower risk of exceeding cost thresholds.

TVaR demonstrates the average of the most extreme values for a given percentile of the distribution, giving an indication of a worst case scenario. Portfolios with lower TVaR values are therefore less risky.

Fuel diversity or resource mix suggests how vulnerable a portfolio will be to changes in fuel prices, as a system heavily dependent on one main resource will be significantly more vulnerable to changes in the price of that resource than a portfolio with a variety of generation options. A portfolio with a greater diversity of fuel sources would therefore be considered to have lower risk than one that relies heavily on a single resource. The variance of a portfolio, in the statistical sense of the term, could be a useful measure of the fuel diversity and spread of the portfolio's resource distribution. As the variance indicates the average of the spread of the variables about the mean, a low value of variance indicates that the energy generation is spread relatively evenly among the various generation options. A high value of variance indicates that a few of the resources are dominating the resource mix.

Water use was only a metric for Arizona Public Service, which operates in a region of scarce water resources and therefore has an interest in choosing generation that does not rely on heavy water usage. This metric could be calculated by historical water usage of a similar sized plant and by interpolating for the scale of a new plant. A high water use would be undesirable for a resource.

CO_2 and other green house gas emissions were used as a metric by many utilities concerned about new regulation that would impose a price on carbon emissions, affecting the dollar per MWh ratio of a high-CO_2 emitting resource and therefore portfolio make-up. If utilities are concerned about the price on carbon, a portfolio with a lower level of carbon emission will be of lower risk. The volume of carbon emissions would be an output of the portfolio simulation process, and direct comparison between portfolios would be possible. If there are a range of carbon emissions for each portfolio due to the simulation process, then measures like the mean and the standard deviation can also be use for this analysis.

Flexibility was used as a metric by utilities that were interested in integrating higher levels of renewable energy from intermittent resources such as wind. As an illustration, the Public Service Company of Colorado was considering the addition of 1,200 MW of wind energy to their system in their 2011 IRP and therefore was interested in adding resources that could manage the variability of wind, e.g. using natural gas peakers. Higher levels of flexibility resources in a portfolio would indicate lower risk of the utility having shortfalls in capacity. Several metrics for measuring flexibility have been proposed in literature by a recent NREL report [36]. These included:

- Percent of GW of installed capacity capable of load-following relative to peak demand
- GIVAR III flexibility scoring framework, where power area size, grid strength, interconnection (transmission), and number of power markets are combined into an overall flexibility score
- Maximum upward or downward change in load that the system is capable of managing in a given time period from a given initial operational state, and
- Expected percentage of incidents in a given time period where the system cannot cope with the changes in net load [36]

Metrics can be combined into scorecards for comparing portfolios. For example, each portfolio could be ranked from n to 1, where n is the number of portfolios being tested, for each separate metric. This would result in each portfolio having a score reflecting their relative merit among the portfolios as a whole.

For example, consider the case of a utility comparing three portfolios: A, B, and C. Each of these will be compared with four different metrics: expected cost, standard deviation of costs, fuel diversity, and tons of CO_2 emitted. Based on the values calculated for each of the metrics in Table 3.3, each portfolio can be given a ranking out of three for each metric (Table 3.4). This analysis would show that portfolio A performed most strongly when considered across all the metrics.

If a utility was very concerned about a particular metric, they could apply a multiplier to ensure that metric carries greater weight in the analysis. For example, the utility could rank their metrics in order of importance – 1) mean cost, 2) CO_4 emissions, 3) standard deviation of costs, and 4) fuel diversity – and give each of these a weight such that the total adds up to 100 percent

Table 3.3: Example of a scorecard for comparing portfolios using metrics and calculations

Portfolio	Expected cost	Standard deviation	Fuel diversity	CO_2 emissions
Unit	Millions	Millions	Statistical variance	Total tons CO_2
A	30	5	189	100
B	25	4	589	500
C	40	3	322	400

Table 3.4: Example of a scorecard for comparing portfolios using metrics, with the metric rankings instead of the calculated numbers

Portfolio	Mean cost	Standard deviation	Fuel diversity	CO_2 emissions	Total
A	2	3	1	1	7
B	1	2	3	3	9
C	3	1	2	2	8

Table 3.5: Example of a score card using weights to reflect utility priorities among metrics

Weights	40%	30%	10%	20%	
Portfolio	Mean cost	Standard deviation	Fuel diversity	CO_2 emissions	Total
A	0.8	0.9	0.1	0.2	2.0
B	0.4	0.6	0.3	0.6	1.9
C	1.2	0.3	0.2	0.4	2.1

(see Table 3.5). This can result in significantly different relative rankings for portfolios, as in this case portfolio B is the best performing.

Metrics can also be useful for direct trade-offs between two performance characteristics of one portfolio at a time. For example if a utility is interested comparing portfolio mean cost to level of risk, they can plot mean cost against a measure of risk (say standard deviation of costs or TVaR) and find the lowest-cost portfolio for a given level of risk i.e. the “efficient frontier”, trading off between the two metrics. In addition, this sort of plot would allow a utility to observe incremental cost changes to obtain a lower or higher level of risk. This is the approach advocated by the Northwest Power and Conservation Council in their sixth regional power plan [10]. While the disadvantage of this approach is increased manipulation of the data, the advantages for decision-making are significant: direct comparison between contradictory metrics and ease of identification of the “best” portfolios under consideration.

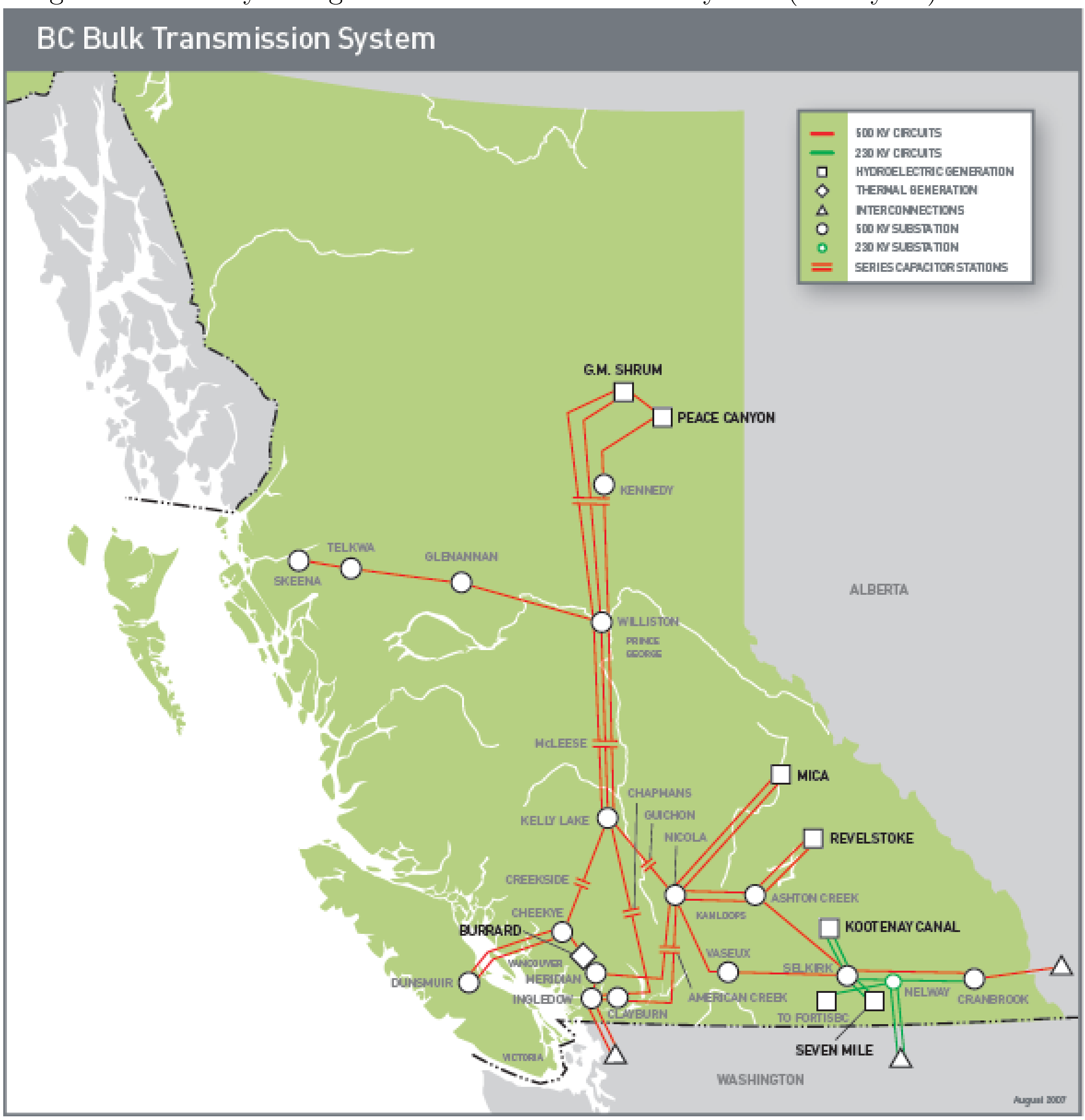
3.3 Application to the BC Hydro system

British Columbia Hydro and Power Authority (BC Hydro) is the main electricity utility in British Columbia, and fourth largest in the WECC [23]. The utility operates 31 hydroelectric generating stations and two thermal stations, providing over 43,000 GWh to a customer base of 1.9 million customers [44, 30]. The vast majority of BC Hydro’s energy comes from their hydro-power generation assets on the Peace and Columbia Rivers (see Figure 3.3 from [45].

BC Hydro, as a crown corporation, adheres to the Clean Energy Act of 2010. This includes the province’s energy objectives (Section 1 of the CEA), of which the most pertinent to BC Hydro’s IRP process are: (a) to achieve electricity self-sufficiency; (b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%; (c) to generate at least 93% of the electricity of British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity [46].

The utility conducts an IRP process every five years [30] and files this document with the Minister, British Columbia Ministry of Energy and Mines. BC Hydro's IRP process uses a scenario-based method with the SO model to build resource portfolios (see Figure 3.4). The SO model's main objective is to minimise the present value of costs net of trade revenue and to ensure that a number of constraints are met. As a large number of portfolios are generated using this method, BC Hydro selects a subset of these portfolios to simulate further. Currently each of the subset of portfolios is simulated in the utility's HYSIM model and Generalized Optimization Model (GOM) to obtain the feasible operational generation and reservoir pool schedule, and system and individual plant incremental costs, as well as the benefits that accrue to the system such as trade benefits from power import/export and shaping benefits. This gives a detailed picture of the actual operation of a portfolio generated by System Optimizer. An example of a finalised portfolio, as presented in the appendices for chapter 6 of the 2013 IRP [30], is shown in Figure 3.6, where each resource has dependable and installed capacity and energy, and an in-service date.

Figure 3.3: BC Hydro's generation and transmission system (BC Hydro)



BC Hydro's current process simulates a portfolio's operation over 60 different water years using the HYSIM and GOM models. For these runs, market price forecasts are inflated/deflated to account for dry/wet years' impacts on the Mid C market. This results in a range of costs for the different water years, giving an indication of the spread of the portfolio costs. However, inflows are not the only variable that is uncertain, and variables like load and gas and power price forecasts can also be varied to assess the performance of the portfolio, based on the inputs to System Optimizer.

3.3.1 Recommendations for BC Hydro's IRP process based on the results of this study

One issue with the current process lies with the performance assessment criteria used to choose the preferred portfolio. Currently the portfolio with the lowest net cost (after accounting for trade revenue) is chosen as the preferred portfolio, which neglects uncertainties in many variables. The current use of the HYSIM and GOM models to simulate portfolio performance with 60 different water years could be augmented by also simulating with different load forecasts, energy prices, and gas prices, leading to broader picture of the potential variation in portfolio performance. A larger number of metrics that represent the uncertainties of the portfolios could then be applied to assess the data, addressing more uncertainties and helping the utility develop a more robust portfolio. A schematic of an updated process is presented in Figure 3.5.

3.4 Conclusions and policy implications

We have examined the various long-term planning methods used by a number of utilities in North America and identified portfolio planning and scenario planning as two key methods used to manage the uncertainty inherent in long

Figure 3.4: BC Hydro's current portfolio development process

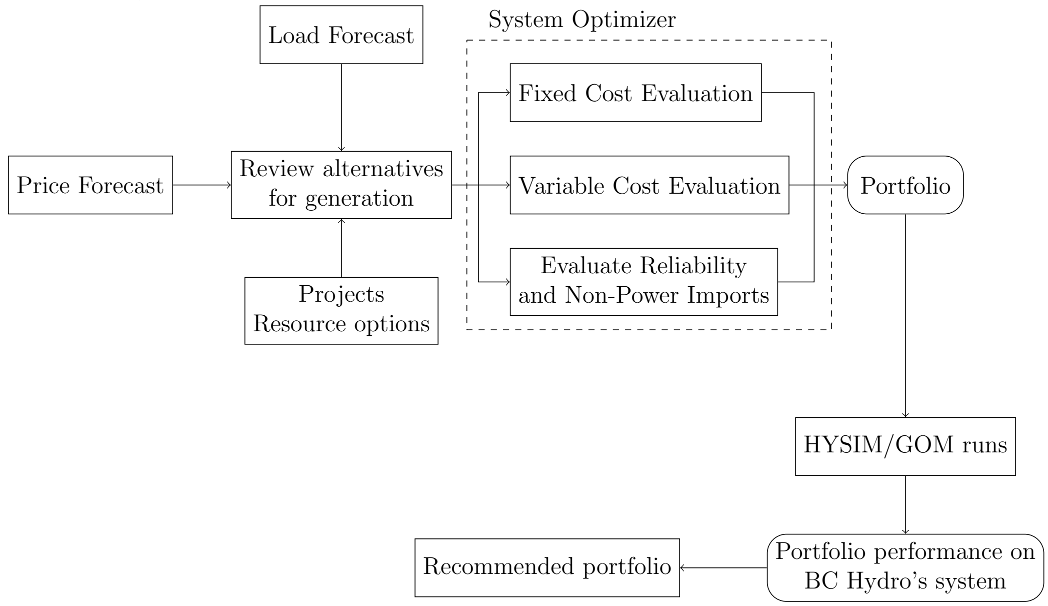


Figure 3.5: Suggested portfolio development and assessment process

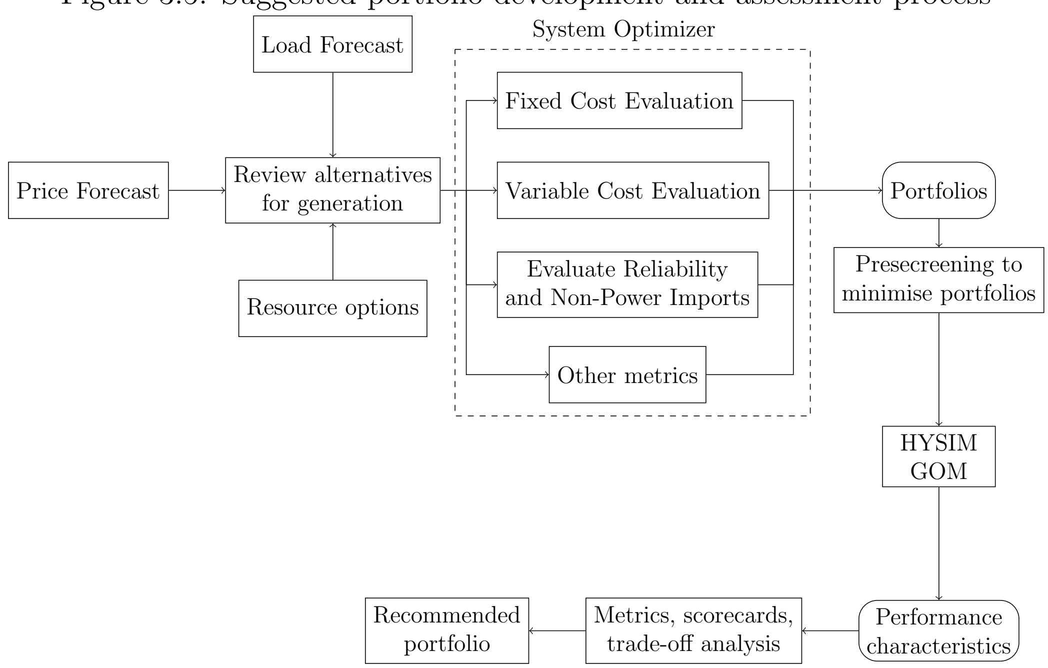


Table 3.6: Example of a BC Hydro resource portfolio (BC Hydro 2013 IRP)

Year	Resource Selected	Capacity - MW		Energy - GWh	
		Installed	Dependable	Firm	Total
2023	Site C	1,100	1,100	5,100	5,100
2028	GMS units 1-5 Cap Increase	220	220		
2029	MSW2_LM	25	24	208	208
2030	Revelstoke Unit 6	500	488	26	26
2032	Pumped_Storage_LM	1,000	1,000		
2033	Wind_PC21	99	26	371	371
2033	Wind_PC28	153	40	591	591
2034	Wind_PC13	135	35	541	541
2034	Wind_PC16	99	26	377	377
2034	Wind_PC19	117	30	441	441
2035	Wind_PC10	297	77	1,023	1,023
2036	MSW1_VI	12	12	100	100
2036	Biomass_VI	30	30	239	239
2036	Run of River LM 80_100	62	10	174	223
2037	Wind_PC09	207	54	713	713
2037	Wind_PC15	108	28	382	382
2037	Biomass_PR	28	28	223	223
2037	Biomass_LM	30	30	239	239
2038	Wind_PC14	144	37	527	527
2038	Wind_PC20	159	41	610	610
2038	Pumped_Storage_LM	1,000	2,000		
2039	Wind_PC11	126	33	473	473
2039	Wind_PC41	45	12	155	155
2039	Wind_PC42	63	16	219	219
2040	Wind_PC18	138	36	486	486
2040	Wind_VI14	35	9	114	114

term planning. The advantages and disadvantages of both methods have been discussed and their explicit treatment of uncertainty examined. Portfolio-based planning has several features that are advantageous in planning under uncertainty. These include: direct selection of portfolio resource combinations, which allows utilities to be explicit in avoiding particularly uncertain resources; simulation of a portfolio with randomised scenarios, providing excellent understanding of an individual portfolio's performance in a wide range of futures; and easier decision making given that portfolio-planning requires manual construction of resource combinations and therefore rarely results in more than tens of portfolios. However, this method appears to be best suited to utilities with small load-resource gaps and/or utilities with strict regulations on the type of resources that can be added, as both of these conditions simplify the portfolio construction process. Scenario-based planning likewise has several advantageous features: portfolio construction in the case where many resources are required is very difficult to carry out manually and is therefore simplified by the use of an optimisation model; use of models for construction of portfolios can be more easily shown to be be unbiased if stakeholders express concerns; and a large number of scenarios, covering many potential futures, yields an equally large number of portfolios that can provide indications of stable resources across disparate futures. This method is perhaps best employed when a utility has a large load-resource gap such that satisfying projected load requires combinations of tens of resources. In such cases it becomes difficult to build resource combinations and test their performance without the use of modelling. It is also interesting to note that this method essentially requires an extra step compared to portfolio-planning, as sensitivity testing after portfolio development for scenario planning is carried out very similarly to simulation of manually constructed portfolios in portfolio-planning (compare Figure 3.1 and Figure 3.2). Our findings discuss the uncertainty and the method of managing that uncertainty in each step of both planning processes, providing utilities with a summary of methods and potentially assisting in modification of their planning processes.

For both methods, our research has noted several ways of assessing portfolio performance to minimise uncertainty. These are to use Monte Carlo simulation to randomly sample from several underlying variables, thereby developing random sensitivity scenarios, and to generate ranges of portfolio performance for each variable. These performance ranges can then be assessed by using metrics such as the mean, standard deviation, and tail value-at-risk. Performance indicators assessed this way could include portfolio net present value, CO_2 emissions, water use, and so on. Other potential assessment metrics could include portfolio resource diversity and flexibility. Assessing a portfolio against several rather than one metric allows for a broader picture of performance and provides high level information for decision-makers and policy developers. The use of explicit metrics also has implications for relationships with stakeholders, as a decision-making process using quantifiable metrics appears to be more transparent, leading to improved stakeholder engagement.

Based on this study, one main recommendation is made for improving BC Hydro's handling of uncertainty in their IRP process: expansion of portfolio simulation combined with extension of existing metrics for portfolio comparison. This could have value in particular for utilities with large hydroelectric generation assets, where the storage and valuation of water is necessary. Further research could investigate other planning methods for uncertainty, such as use of dynamic programming, and its application to systems similar to BC Hydro's.

Chapter 4

Conclusion

Chapter 1 has presented a survey of the IRP processes for a sample of North American electric utilities. Our research suggests that two main methods of planning are used: portfolio-based planning and scenario-based planning. A notable point was that scenario-planning was more popular among larger utilities (i.e. greater than 4,000 MW of generating capacity), while smaller utilities favoured portfolio-planning. This trend was not observed in Californian utilities, due to the nature of the state's electricity market and regulation.

Chapter 2 analysed BC Hydro's current long-term planning process and identified it as following the practice of scenario-planning. Examination of the portfolio simulation after portfolio construction with SO suggested that while water storage and water value were being well simulated, other contributing factors to uncertainty such as energy price and load were not considered. Inclusion of these variables in the simulation would allow BC Hydro to assess portfolios over a broader range of characteristics, which is beneficial for uncertainty management. However, increased simulation for more variables also complicates the assessment of which portfolio performs best. For this reason, we recommend the development of performance metrics other than lowest cost – examples being width of cost distribution, flexibility, and fuel diversity, among others – and the formalisation of portfolio performance analysis in the form of explicit metrics and scorecards. In addition, there is currently no mechanism for considering the benefits brought by a portfolio, such as generation of income by export, in addition to the costs of a portfolio. Consideration of such benefits has the potential to modify a portfolio built by SO. Therefore our research suggested that BC Hydro implement the following recommendations:

- Continue to use the current capacity expansion model (System Optimizer) for developing portfolios from multiple scenarios
- Use HYSIM/GOM for further sensitivity analysis of individual portfolios, expanding beyond the 60 water years and expanding to include alternative loads, gas prices, and energy prices
- Develop metrics and scorecards and/or efficient frontier analysis for assessing portfolio performance
- Develop a GUI for running HYSIM to streamline the process of running the increased number of simulations. This can be done by enhancing the existing GOM GUI
- Investigate the potential use of dynamic programming for portfolio selection and compare its output with that of System Optimizer

In Chapter 3 the various long-term planning methods were broken down into their component steps and each step analysed for its effect on uncertainty management.The advantages and disadvantages of both methods have been discussed and their explicit treatment of uncertainty examined. Portfolio-based planning offered advantages in direct selection of portfolio resource combinations, which allows utilities to be explicit in avoiding particularly uncertain resources; simulation of a portfolio with randomised scenarios, providing excellent understanding of an individual portfolio's performance in a wide range of futures; and easier decision making given that portfolio-planning requires manual construction of resource combinations and therefore rarely results in more than tens of portfolios. However, the method appeared to be limited in application, being best suited to utilities with small load-resource gaps and/or utilities with strict regulations on the type of resources that can be added, as both of these conditions simplify the portfolio construction process. Scenario-based planning had advantages in simplified portfolio construction through the use of an optimisation model for the case where many resources are required to fill the goad-resource gap; more easily justified decisions as stakeholders can be shown that portfolio development is by a model; and a large number of scenarios, covering many potential futures, that yields an equally large number of portfolios that can provide indications of stable resources across disparate futures. For both methods, our research has noted several ways of assessing portfolio performance to minimise uncertainty. These are to use Monte Carlo simulation to randomly sample from several underlying variables, thereby developing random sensitivity scenarios, and to generate ranges of portfolio performance for each variable. These performance ranges can then be assessed by using metrics such as the mean, standard deviation, and tail value-at-risk. Assessing a portfolio against several rather than one metric allows for a broader picture of performance and provides high level information for decision-makers and policy developers.

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