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Water Resource Risk and Technology Investment under Uncertainty

A real options approach to the valuation of water conservation technology at a thermoelectric power plant

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WATER RESOURCE RISK AND TECHNOLOGY
INVESTMENT UNDER UNCERTAINTY

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Abstract

Supporting thermoelectric power generation requires a significant quantity of water, primarily for cooling operations. Lack of available water due to physical scarcity or thermal permit limits associated with the Clean Water Act 316 (a) can result in a forced curtailment of plant operation, known as a “derating event.” Depending on the duration and severity of this derating event, a utility can realize millions of dollars in economic loss. To prevent such events, a power plant can invest in alternative cooling technology that reduces the plant’s dependence on large quantities of water for cooling operations. Such investments however, may be difficult to justify due to large capital costs for water conservation technologies and highly uncertain future cost of derating events - future derating costs are a function of climate and energy market prices. Thus, the capital decision to invest is complex. Traditional valuation approaches, like Net Present Value (NPV) analysis, are unable to properly value irreversible investments in environments of high uncertainty because they fail to account for managerial discretion and flexibility in investment. Real options analysis (ROA) has been proposed as a promising solution to the deficiencies of traditional valuation methods when facing risky technology investments or ventures. The valuation technique, rooted in financial option theory, incorporates “Real option thinking” - the managerial flexibility to capitalize on opportunities as they arise and minimize the impact of threats - is precisely what is needed when faced with the uncertain future of irreversible technology investments. This paper applies ROA to an evaluation of the investment in water saving cooling technology at the Allen Steam Station in the Catawba River Basin of North and South Carolina. The results indicate that the use of an NPV analysis leads to an undervaluation of the project because the option value - the value of managerial flexibility - is not included in the valuation. The flexibility of managers is an important criterion for making decisions regarding sunk cost investments and firms should evaluate investments with techniques that incorporate this option value.

Contributors

This Practicum was initiated with the intent to be the first objective in a larger project focusing on the creation of a strategic investment tool that coupled the use of a real options framework and a watershed based model (eg. Watershed Risk Analysis Framework, WRMF). The larger project has been submitted for a grant to the National Science Foundation (NSF) under the title: *"Sustainable Water for Power Generation: An Option-Based Decision Support System for Cooling Technology Investments."* Much of the information prepared for the NSF proposal has been incorporated into this paper.

The initial idea for this project was the result of learning in Gautam Kaul's Sustainable Finance class taught at the Ross School of Business (FIN 637). While John Rice is the principal author of this Practicum, the results and portions of the text in the preceding pages are a function of the past and ongoing efforts of a number of individuals across several schools at the University of Michigan. These members include:

- Peter Adriaens: Faculty Advisor, Civil and Environmental Engineering and Ross School of Business
- Gautam Kaul: Faculty Advisor, Ross School of Business
- Christian Lastoskie: Civil and Environmental Engineering and Ross School of Business
- Nate Troup ('09): ROA Model Advisor, Ross School of Business
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Michael Moore (Faculty Advisor) of the School of Natural Resources and Environment is also recognized and thanked for providing an objective review of the research, methodology, model, results, and final deliverable.

Finally, let me recognize Rachel Permut of Duke Energy, a 2008 graduate of the Ross School of Business and School of Natural Resources and Environment. Rachel internally championed the idea of a project within the Duke organization to investigate the applicability in the use of real options to evaluate water technologies at Duke. Without Rachel, the project would not have had access to much of the data used in the analysis or perhaps occurred at all.

Section 1: Background

1.1 Energy-Water Nexus

The political, business, and investment communities are paying increased attention to energy independence, efficiency, and improved renewable sources. However, what appears to often be overlooked in these conversations and debates is the direct relationship between our country's energy choices and water resources. Yet, energy creation and water resources are inextricably linked to one another. The reality is that under current power production schemes, to sustain reliable energy production, a detailed understanding of the interdependencies of water and energy systems is necessary. Sandia National Laboratory and the Department of Energy highlight the importance of the Energy-Water Nexus:

> "The continued security and economic health of the United States depends on a sustainable supply of both energy and water. These two critical resources are inextricably and reciprocally linked; the production of energy requires large volumes of water while the treatment and distribution of water is equally dependent upon readily available, low-cost energy. The nation's ability to continue providing both clean, affordable energy and water is being seriously challenged by a number of emerging issues" [1]

In short, the Energy-Water Nexus is based on two truths: 1) Energy is required to make use of water and; 2) Water is needed to make use of energy.

Regarding the first truth, the United States expends an enormous amount of energy lifting, moving, processing, and treating water at every phase of its extraction, distribution, and use. Approximately 5% of all electricity consumed in the U.S. is used to treat and distribute water. In certain regions of the US, energy demand for water resources is even greater [2]. In California, the electricity demand to treat and distribute water is more than 7% of total state demand, and studies show that more than 19% of its total electricity usage is related to water (pumping, treating, distributing, heating, cooling, pressurizing, etc) [2].

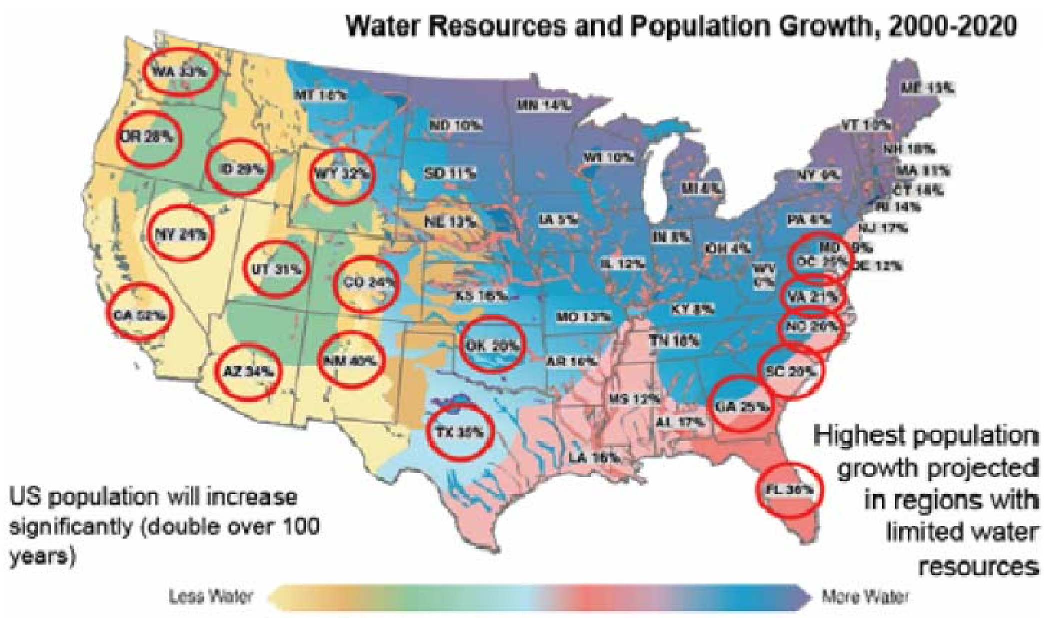


Figure 1.1: Highest population projected in areas with most limited water resources [3]

Regarding the second truth, water is used in the generation of most forms of traditional turbine-produced electricity (and in some forms of renewable produced energy). Water is sometimes a direct input to the generation process, but more often it plays a role at various intermediate phases of electricity generation, such as plant cooling processes in thermal and nuclear generation.

Water's necessity in energy production is the key foundation to this Practicum (Figure 1.2). As John Wolfe of LimnoTech, a water engineering consultancy in Ann Arbor, Michigan, points out:

> "Water use remains a contentious issue for the U.S. [energy] industry, whose plants account for 40% of freshwater withdrawals nationwide, but only 3% of freshwater consumption…. As America's population and electricity use continue to grow, power plants are increasingly competing with farms, factories, businesses, and households for limited supplies of water. Because the growth of fresh water supplies is limited, growth in electricity demand can be met only by developing [and implementing] technologies that reduce the volume of fresh water required per kilowatt-hour of power generated" [4].

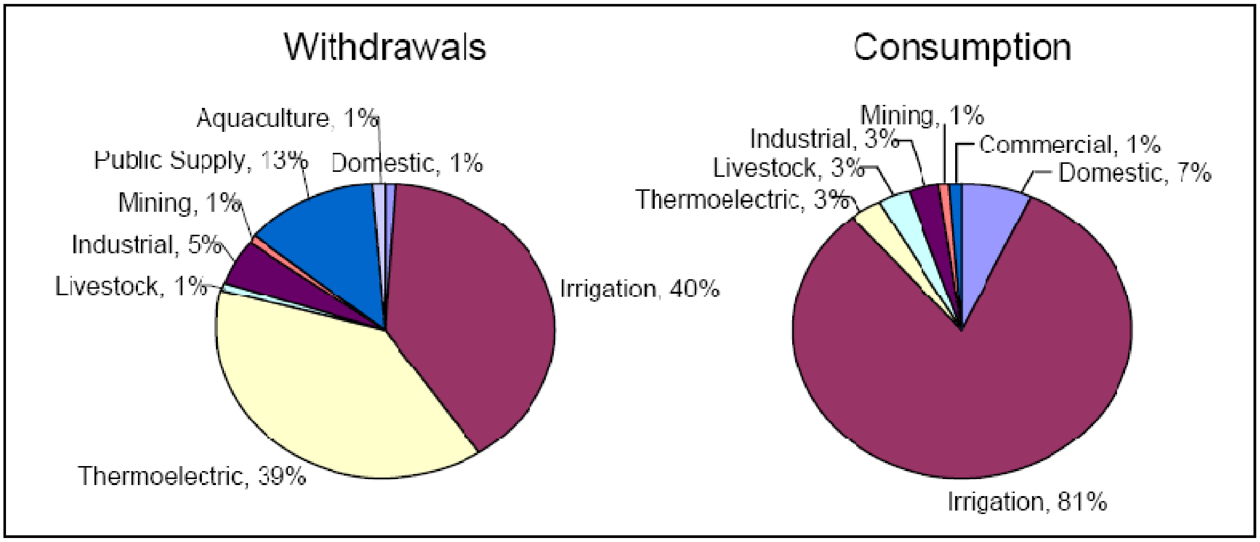


Figure 1.2: Total Water Withdrawals and Consumption by Sector in the US [5]

Furthermore, the issue of freshwater supplies and energy production becomes increasingly complex when regionally examined. Global climate change will likely impact the future geographic distribution of water across regions and drive emissions management policies [6,7]. These policies will dictate how plants operate and use available water supplies. For example, the adoption of a carbon C-sequestration approach to mitigate climate change may increase water usage at individual power plants more than 30% [8].

1.2 Water Requirements for Thermoelectric Generation

Supporting thermoelectric power generation requires a significant quantity of water.1 For example, almost 220 billion gallons of water are withdrawn each day for cooling large power plants. [9] Cooling water, used to condense steam in the power generation process, is typically the largest source of overall plant water demand, but water use can vary significantly depending on the design of the cooling system installed at thermoelectric plant. Currently, three different processes are used in cooling for power production. The first two, most commonly used, are once-through cooling and closed-loop cooling (recirculating); the third, much less frequently used, is dry cooling (Figure 1.3). Dry cooling is typically more water efficient, both from a capital cost and an operational cost because it uses little or no water and needs less maintenance than cooling towers that require water. However, dry systems have drawbacks including both higher upfront capital costs than wet cooled systems and a small efficiency penalty (i.e. less MWh under dry cooled system are produced than under wet cooled systems) [10]. Beyond these three major types of systems, there are also hybrid systems that incorporate dry-wet designs in

[1] Thermoelectric plants are coal, oil, natural gas, and nuclear fueled power generators using a steam turbine based on the Rankine thermodynamic cycle

attempt to take advantage of the benefits of each system while limiting the downsides of each. Below is a brief description of each type of system.

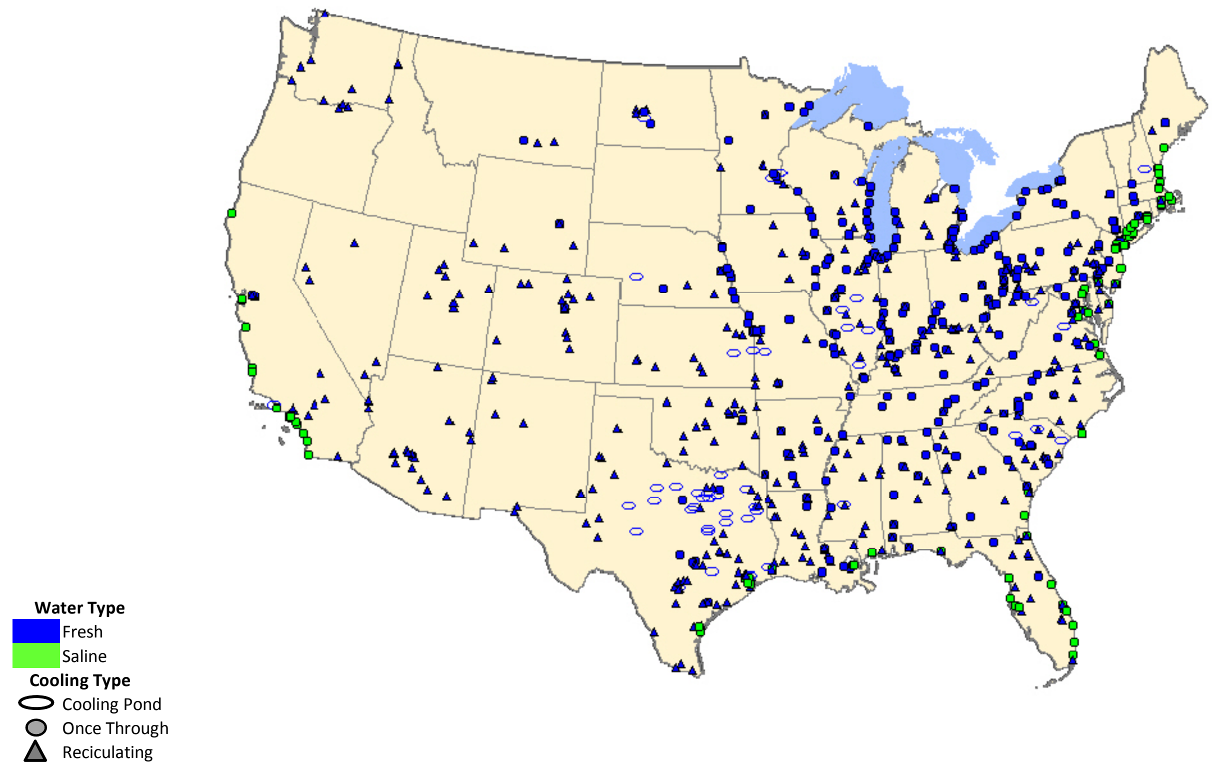


Figure 1.3: Cooling System by Technology and Water Source [5]

Once-Through Cooling

Once-through cooling systems use nearby water to help cool the condenser water. Typically, river or lake water is passed through a heat exchanger to both condense steam and absorb heat, and the water is then discharged back to the river/lake at elevated temperature (1.4). Each plant holds a permit that allows a specified allowable temperature rise in cooling water before being discharged back to the environment. A typical steam plant with a once-through cooling system can use hundreds of millions or billions of gallons of water per day.

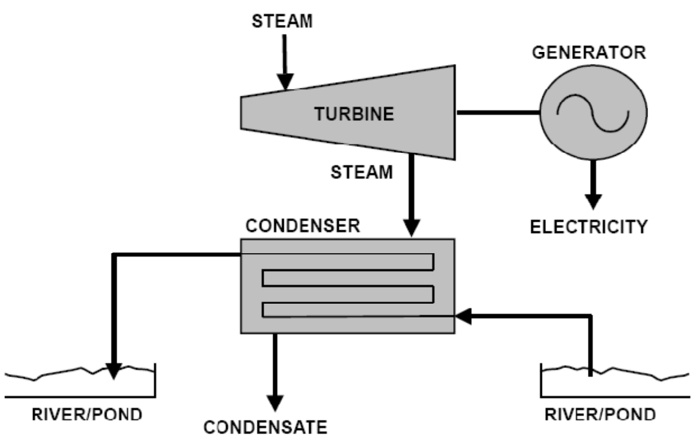


Figure 1.4: Once-through Cooling [11]

Despite this, water consumption at the power plant is minimal because the water does not directly contact the air. Also, temperature increases of river water increase the evaporation rate, thus indirectly increasing water consumption (Table 1.1).

Closed-Loop Wet Cooling

A closed-loop cooling system was designed to minimize the amount of water withdrawn from the river. In this system, the condenser water still exchanges heat with water in a heat exchanger, but the cooling water is recycled between a cooling tower and a heat exchanger (Figure 1.5). In this system, the cooling water is cooled by evaporating a percentage of the water to the environment. Because the water evaporates, a make-up water supply must account for the consumed water. The make-up water typically comes from a nearby water source (river, lake, groundwater). This system consumes more water than once-through types because the entire energy exchange derives from the evaporation of the water—a consumptive use. While these systems only withdraw water to make up for the evaporated portion, they consume more water overall (Table 1.1).

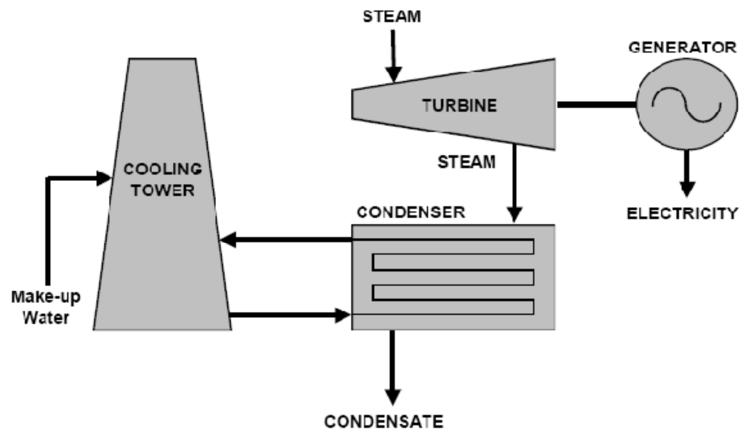


Figure 1.5: Closed-Loop Cooling [11]

Dry Cooling

Dry cooling is the most attractive cooling system when considering water withdrawals and consumption for power production. Dry-cooling systems function without having the water contact the air. The hot condenser water passes through a liquid-to-air heat exchanger containing many fins on pipes in the condenser. These fins increase the condenser's surface area, thus increasing the amount of heat removal (Figure 1.6). Dry cooling typically requires a fan to aid in heat removal. Dry cooling is highly attractive since water withdrawals and consumptions

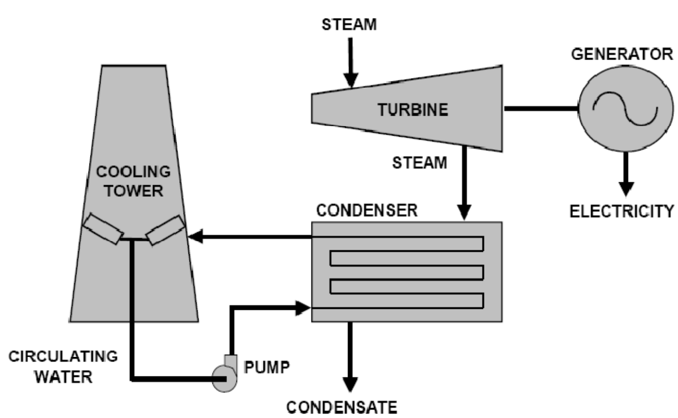


Figure 1.6: Dry Cooling [11]

are nearly zero -- almost no water is needed for dry cooling. However, dry cooling systems have lower thermal efficiencies than wet cooling systems, thereby reducing MWh's in plant output (typically less than 1%) [Appendix A].

The Heller Hybrid System

The Heller System is a combination system, or hybrid system, that uses primarily indirect air cooling via a dry cooling tower. By indirect cooling, the waste heat from the power plant is exchanged in a condenser to a closed circuit cooling water loop. The warmed water is then cooled by the ambient air via natural draft cooling in heat exchangers. In order to take advantage of the wet cooling system's higher efficiency over dry cooling, the Heller can be retrofitted or manufactured with a water spraying system. This water system allows additional cooling by distributing water over the fins of the heat exchanger. By spraying the water instead of the traditional once-through wet cooling system, which requires massive amounts of available water, water-efficiency is captured. The Heller hybrid system incorporates this additional water spraying system. There were several hybrids of the Heller system developed to improve water conservation relative to wet cooling, reduce investment costs relative to dry cooling, and improve both environmental and summertime turbine outputs (Appendix A).

Table 1.1: Withdrawal and Consumption for Cooling System Types [12]

Generation Type	Cooling Water System Type	Withdrawal Factor (gal/MWh)	Consumption Factor (onsite water use only) (gal/MWh)	Consumption Factor (Onsite plus Downstream Evaporation (gal/MWh)
Coal	Once-through	27,080	105	300
	Wet Cooling Tower	497	428	537
Nuclear	Once-through	31,497	137	394
	Wet Cooling Tower	1,101	624	624
Oil and Natural Gas	Once-through	22,740	9	NA
	Wet Cooling Tower	250	16	NA

1.3 Power Production, Water Scarcity and Water Conservation Technologies

The United States is the largest energy consumer of energy in the world in terms of total use, using over 100 quadrillion BTUs per year [13]. The U.S. ranks seventh in energy consumption per-capita with 12,924.224 kWh per person in 2007 [14]. The country is only surpassed in energy usage per capita by countries like Iceland or Kuwait, that have access to large reserves of traditional and renewable energy sources, such as oil, geothermal, or hydropower [14]. While growth in US electricity consumption demand has steadily decreased over the last 50 years, the US will still need an additional 26% installed capacity by 2030 primarily driven by population growth [15,16].(Figure 1.7, 1.8). The makeup of future power production is uncertain, but expected to be largely driven by coal, natural gas, and nuclear (Figure 1.8) [15].

The increases in power production needs will have a significant impact on water resources. For thermoelectric capacity additions using conventional cooling tower systems, a corresponding 21% to 48% increase in freshwater consumption will occur in next 25 years [16]. Even in the southeastern U.S., where freshwater is not ordinarily viewed as a limiting resource, an extended drought in 2007 led to the imposition of water use restrictions normally associated with water conservation initiatives in western states.

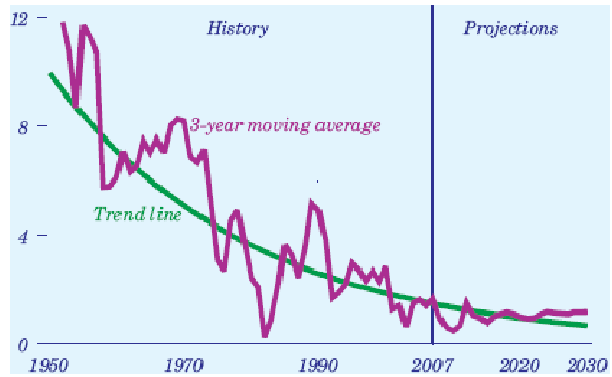


Figure 1.7: US Electricity Demand Growth- 1950 to 2030 (percent, three year moving average) [15]

Predictably, shortfalls in available freshwater disrupt local economies and engender disputes over water appropriations between energy, municipal, and agricultural interests. Surprisingly, these disagreements are occurring in traditionally water-rich northern states such as Minnesota and Illinois, where permits for new ethanol plants have been rejected over concerns about excessive water use and mining of groundwater resources [17]. Similarly, frequency of renegotiated operating permits is increasing in Georgia, North Carolina, Arizona, and California for coal-fired and nuclear power plants because of water concerns.

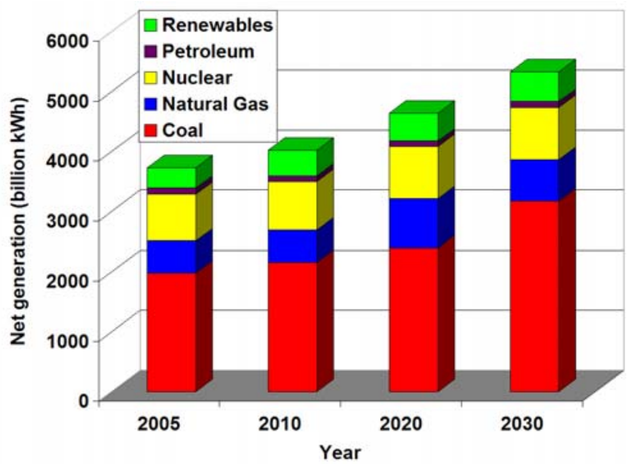


Figure 1.8: Projected Electricity Demand through 2030 [15]

Climate change may potentially reallocate freshwater resources and affect water temperature over the next several decades. Although uncertainty exists for regional water resources, it is generally held that climate change will increase the intensity of droughts, floods and peak summer temperatures [18]. Increases in peak summer temperatures will lead to increased source water temperatures. These conditions can negatively affect thermoelectric plants using once-through cooling systems in several ways. First, increased source water temperatures decrease the assimilative heat capacity of cooling water and reduce turbine backpressure, thus decreasing the overall plant output [5]. Second, the cooling water discharged back to the source water body is warmed and sometimes alters local species' growth rates, feeding behavior, or other factors. Section 316(a) of the Clean Water Act addresses the environmental impact associated with thermal pollution from power plants or any industrial facilities discharging effluent into surface waters [19]. Increases in peak summer lake or river temperatures decreases the water body's ability absorb thermal pollution. If lake or river temperatures near the cooling water outfall are not able to remain below the permitted levels, the plant may have to curtail operation until temperatures fall under the threshold. The curtailment of operation is known as a "derating event".

Technical Solutions to Derating Events

Given that the capital costs for the construction of new thermoelectric plants are typically written off over a 40-year life cycle, it is prudent to consider whether the water resources presumed to be accessible at a plant location will in fact be available over the full service lifetime of the generating facility. Indicators of changes in water allocation and pricing contracts were presented at the 2009 Electric Utilities Environmental Conference, impacting utilities in the Southwest and Southeast.

To address the water demands of once-through systems, the use of retrofits with helper towers or groundwater and treated wastewater are considered to dilute discharge and mitigate temperature problems. As a result of Clean Water Act Section 316(b) provisions and public pressures, most jurisdictions now discourage or prohibit construction of new once-through cooling systems.2 AS noted earlier because closed-loop systems cool by evaporation from towers or cooling ponds, they consume more water than once-through systems, but withdraw a lot less (Section 2.2). The actual rates of water withdrawal and consumption depend on the plant's generation technology and environmental conditions. As new cooling technologies are developed, thermoelectric plant management and decision makers will have increased options to enable them to reduce water-related costs and increase plant profitability. It has been argued that water-conservation technologies, alone or in combination, could raise annual margins by 1 to 3 % from savings in pumping and other costs [8]. This estimate does not include the potential gains from reducing water related derating events and, therefore, the profitability impact of water saving technologies could be even greater.

1.4 Uncertainty and the Cost of Water Unavailability

Water is clearly a critical input in the continuing operation of a thermoelectric power plant. Water shortages due to either drought or increased demand from population and industrial growth can limit the physical availability of source water to a plant. Alternatively, sufficient quantities of water may be available for uptake into the plant's cooling system, but water temperature constraints may impair the plant's ability to operate efficiently or at all. Regardless, if water is not available, either due to physical availability or temperature constraints, then a

[2] Section 316(b) of the Clean Water Act (CWA) requires EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement (being pinned against screens or other parts of a cooling water intake structure) or entrainment (being drawn into cooling water systems and subjected to thermal, physical or chemical stresses).

plant will be forced to curtail operation. As mentioned earlier, the curtailment of operation at a plant is known as a “derating event” and equates to reduced MWh generation. If a plant suffers extensive or extended derating events the plant can realize significant economic loss. Consequently, plant operators have the incentive to balance the costs of derating events vs. the cost of avoiding derating events with investments in technologies like dry cooling systems.

However, this balance is extremely difficult for a plant operator because of the large amount of uncertainty surrounding future derating events. These uncertainties include: (1) The frequency and severity of derating events, and (2) the cost of derating events. The frequency and severity of derating events are a function of climatic variation (i.e. drought, summer temperatures, etc) and therefore, highly unpredictable over the short and long term. The cost of derating events is also tied to the regional energy markets. For example, derating event that occurs when power is selling at $20/kWh will be less costly than if the derating event occurs when the spot price of a kWh is $115. Energy markets are extremely volatile and unpredictable, further confounded by their correlation with climatic variables.

Numerous methods have been proposed to capture the impact of reduced power production in electric power systems in order to help facilities optimize investment in technological solutions [20-22]. This practicum approaches the solution from a financial options and modeling perspective. However, before this approach is introduced, it is important to understand how we capture the impact of reduced power production. In the case introduced in the Section 2, the cost of a de-rating event at a plant is a function of two types of costs - a replacement cost and a market cost. To understand these two types of costs we use a simplified example. In Section 2, we will introduce a more complex example that serves as our case study. In our simplified example:

Due to elevated water temperatures and a need to comply with its permit governed by CWA 316(a) regulation, Plant A experiences a derating event which results in a curtailment of 100,000 MWh over the duration of the event. As a result of the 100,000 MWh reduction in production, the utility must increase the production at Plant B in order to meet contractual energy deliveries (also called Native Load). However, because the utility is a profit-maximizing firm, we can assume that the cost per MWh at Plant B (Cb) is higher than the cost of production per MWh at Plant A (Ca). If this were not true, production of the 100,000 MWh would never have occurred at Plant A. Given Plant B power production is more costly, the utility will only increase Plant B production by 80,000 MWh in order to meet system demand and deliver on negotiated contracts. Thus, there is a net system production decrease of 20,000 MWh. If the derating event had not occurred and 100,000 MWh had been produced at Plant A, 80,000 MWh would have been delivered to the system users with negotiated contracts and the remaining 20,000 MWh would have been sold into a regional interconnect system, like the PJM Interconnection, at market price (Mp).

In this example, there are two costs realized by the utility. The first cost is a replacement cost because the cost of producing a Plant B is greater than the cost of production at Plant A. The second cost is an opportunity cost or market cost - the lost revenue associated with selling excess system power in to the regional interconnect. At the most basic level, the total cost of the derating event can be expressed as:

$$\textit{Total Cost} = \textit{Replacement Cost} + \textit{Market Cost}$$

$$\textit{Total Cost (\$)} = [80{,}000\ MWh\ (Cb - Ca)] + [20{,}000\ MWh\ (Mp\text{-}Ca)]$$

In an extreme case, perhaps in the case of widespread prolonged drought, there is the possibility that other plants may not be able to increase production to compensate for lost production at Plant A. In this case, the utility would need to purchase power from the market to meet its native load obligations. For example, if Plant B could only generate an additional 70,000 MWh, then 10,000 MWh would be purchased from the market and the 20,000 MWh that could have been sold into the market, absent the derating event, would still be an considered opportunity cost.

$$\textit{Total Cost (\$)} = [70{,}000\ MWh\ (Cb - Ca)] + [20{,}000\ MWh\ (Mp)] + [10{,}000\ MWh\ (Mp)]$$

Finally, it is important to note that a derating event at one plant results in a reduction in MWh generation. Therefore, the marginal cost per MWh at Plant A (MCA) will increase and the cost per MWh at Plant B (MCB) will decrease (fixed costs can be ignored due to amortization at both plants). Thus, a more appropriate Total Cost equation may be:

$$\textit{Total Cost (\$)} = [80{,}000\ MWh\ (MCB - MCA)] + [20{,}000\ MWh\ (Mp - MCA)] + [0\ MWh\ (Mp)]$$

In summary, the challenge faced by utility mangers is two-fold: the frequency and severity of derating events in the future are unknown; costs associated with each event are uncertain. The initial reaction is to try to find a solution to limit derating events. Intuitively, it would seem plausible that water saving technology investment, for example a hybrid (wet/dry) system, would prove beneficial because it would allow plant managers to react to changing water conditions and shift the type of cooling operations. However, due to the high expense of this technology investment, traditional Discounted Cash Flow (DCF) valuation approaches may demonstrate the project to have a negative NPV and the project would not be pursued. In other words, the DCF analysis would suggest the plant was better off accepting the cost of derating events rather than trying to mitigate the events. This may be true in some cases, but it also important to understand the limitations of the DCF technique in highly uncertain environments. The technology investment question and the use of NPV to evaluate a potential technological solution is the cornerstone of this Practicum.

Over the next four sections of this Practicum, we will discuss how DCF does not take into account the contingent decisions available to a manager, thus limiting managerial flexibility to act on those decisions. We will illustrate that DCF does not take into account that a rational managerial will limit downside risk. In general, it is our assertion that a full reliance on the DCF approach may lead to the rejection of promising projects because of an undervaluation of the project due to its approach to uncertainty.

Following this discussion, we will introduce a valuation approach known as real options analysis (ROA), which offers an additional analysis tool. This tool may be used in conjunction with traditional approaches that address the limitations of DCF, because it captures the value of options and flexibility associated with investment and project selection [23]. By making options that exist in the business environment explicit and quantifying their value, management is better able to make rational decisions in uncertain environments based on more complete information.

Section 2: Power Generation in the Catawba-Wateree River Basin

The investigation of real options analysis for use in technological investment valuation is conducted through a single case study of a thermoelectric plant in the Catawba River basin, the Allen Steam Station. The Basin contains seven other fossil generating power plants that could have also been evaluated. This section begins with a brief description of the hydrologic and power production characteristics of the Basin, and then provides a description of the Allen Station, water concerns, and associated derating events.

2.1 Water Resources of the Basin

The Catawba-Wateree River Basin is located is located in the southwestern region of North Carolina and the north-central region of South Carolina (Figure 2.1). The Catawba River originates in the mountains of North Carolina and flows through a series of lakes and free-flowing stretches for 224 miles until it meets Big Wateree Creek and Lake Wateree. Downstream of the Lake Wateree Dam, the river name changes to the Wateree River. The Basin encompasses 3,305 square miles of the state of North Carolina and 2,322 square miles of South Carolina [24, 25].

The main channel of the river is impounded by a series of 11 hydropower reservoirs that start at Lake James, in the mountains or North Carolina, and run to Lake Wateree, in South Carolina (Figure 2.2). The longest stretch of free flowing river is only 17 miles [26]. All 11 reservoirs on the Catawba-Wateree River are owned and operated by Duke Energy through a license from the Federal Energy Regulatory Commission (FERC). The system of 11 reservoirs is known as the Catawba-Wateree Hydro Project. The Catawba-Wateree Hydro Project spans more than 200 river miles and encompasses approximately 1,700 miles of shoreline within nine counties in North Carolina and five counties in South Carolina [27]. As the

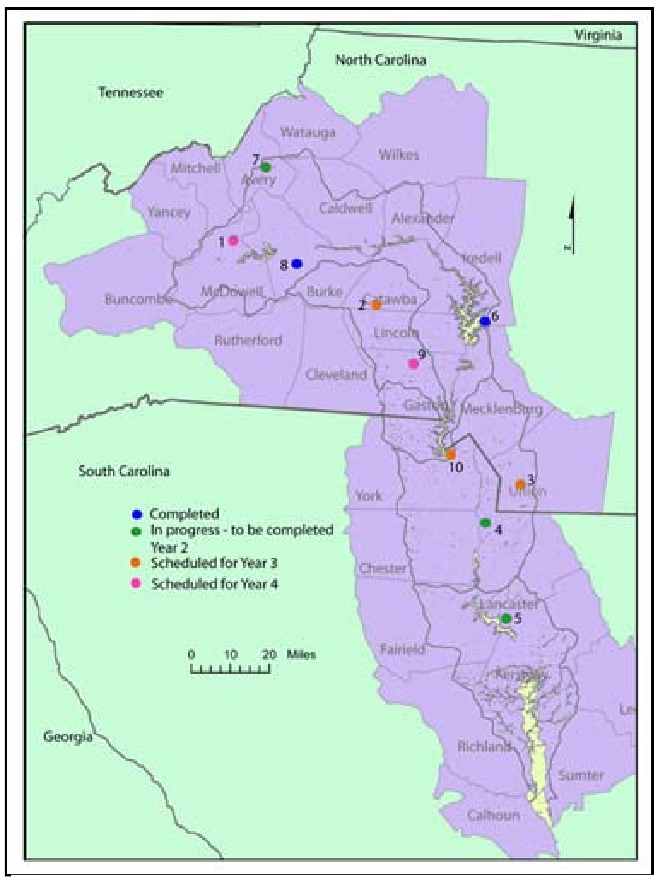


Figure 2.1: The Catawba River Basin [28]

name implies, the principal purpose of the Project is to provide water necessary for thermoelectric cooling and hydroelectric power generation. However, there are numerous other stakeholders in the basin that rely on the reservoir's capacity to meet municipal, industrial, agricultural and environmental demands.

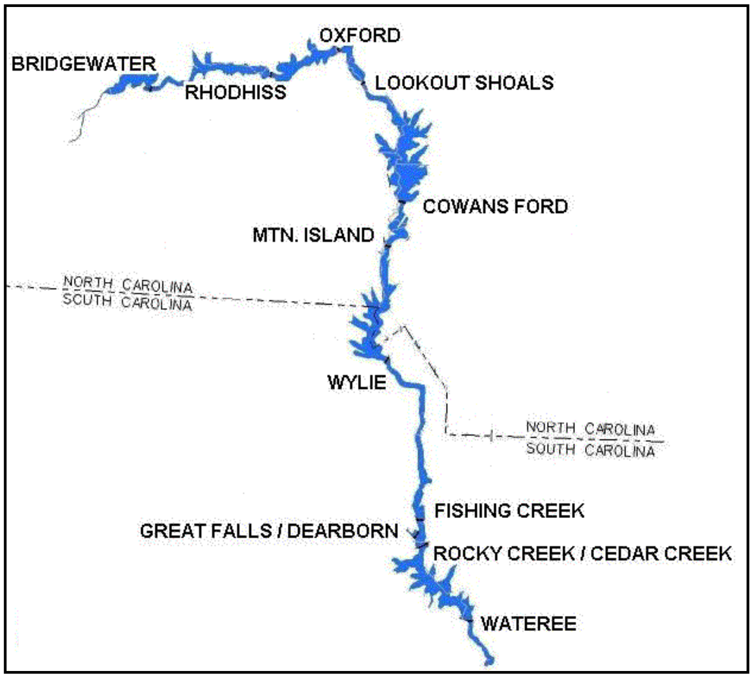


Figure 2.2: Lakes of the Catawba-Wateree Hydro Project [29]

2.2 Water Concerns in the Basin

While persistent droughts have been common in the western United States throughout this century, in the last decade the Southeast finds itself as one of the nation's most rain-starved regions. In 2007, the Catawba River Basin and the rest of the Carolinas experienced the worst drought on record, surpassing the drought that took place between 1998 and 2002 [29].

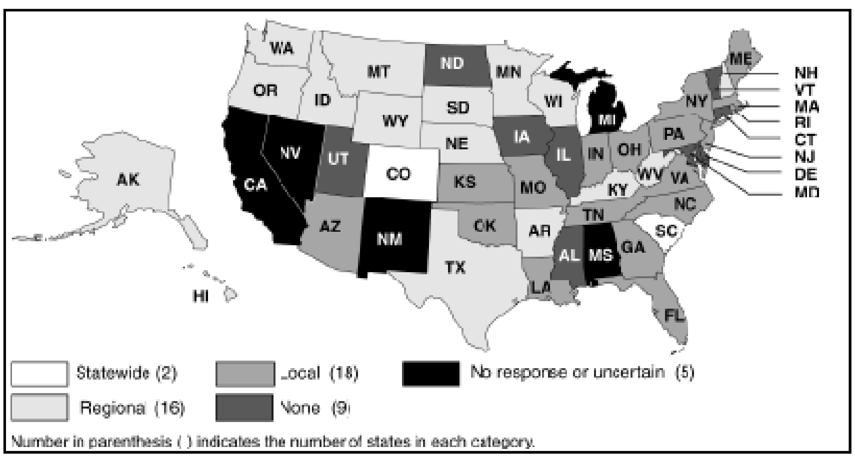


Figure 2.3: Extent of State Shortages Likely over the Next Decade under Average Water Conditions [30]

The region's hydrologic characteristics point to a very real struggle to maintain an adequate water supply for potable, industrial, commercial, recreational, energy, and environmental purposes on both a local and state level (Figure 2.3). Though not directly the focus of this study, climate change (i.e. changes in temperature, evaporation rates, and precipitation patterns) may exacerbate this struggle and be especially relevant for large water users such as utilities, municipalities, and agriculture.

2.3 Power Production in the Basin

In 1958, Duke received a 50-year license from the Federal Energy Regulatory Commission (FERC) to operate and maintain the reservoirs of the Catawba-Wateree Hydro Project.[3] The Hydro Project, comprised of 13 hydropower stations and 11 reservoirs, is the backbone of Duke Energy's power generation fleet, providing 841 megawatts of hydropower (enough to power 103,000 homes) and cooling water to more than 8,100 megawatts of fossil and nuclear generation. The hydroelectric capacity of the Catawba-Wateree project allows the systems to economically meet peak loads demands because the plants can be started quickly to provide electricity when demand is high [27].

However, cooling water from the lakes, though available in terms of quantity, may be unacceptable at times for use as cooling water due to thermal constraints. For example, during the summer of 2007, a fossil generating station owned and operated by Duke Energy experienced several significant generation derating events due to National Pollutant Discharge Elimination System (NPDES) thermal limits and /or flow restrictions.[4] These events resulted in economic loss of over $13 million in August alone across all Duke plants [29]. As mentioned in Section 2.1, prior to 2007, the worst drought on record (1998-2002) led to a series of derating events at six of the eight fossil stations in the Carolinas that resulted in lost generation of 944,000 MWh [29]

2.4 The Allen Steam Station

The real options analysis case study presented here is focused on the Allen Steam Station. The Station, located in Gaston County, North Carolina, is a five-unit coal-fired generating facility.

[3] The FERC license to operate was a 50 year agreement, the license expired in 2008. As part of the relicensing process, Duke solicited input from numerous regional stakeholders regarding key issues that should be studied and evaluated during relicensing. Several requests were made to evaluate the Catawba-Wateree Project's ability to reliably support future water supply needs for the region. As a result of these requests, and concerns over the impacts to water supply caused by the extended drought that occurred from 1998 to 2002, Duke elected to proceed with this Water Supply Study. It was because of the re-licensing effort that much of data on derating events was monitored by Duke and was subsequently able to be utilized in this analysis [27].

[4] As authorized by the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. This includes thermal pollution.

Units 1 and 2 began operating in 1957; unit 3 in 1959; unit 4 in 1960 and unit 5 in 1961. All five units of the thermoelectric plant have capacity to generate 1140 MWe (Figure 2.4) [27].

Plant	Unit #	Summer Rating MW	2003-2007 Avg Annual MWh	2003-2007 Avg Annual Ops Hours	Start/ Retire	County	State	Primary Water Source	Cooling System	Water Source
ALLEN1	2	165	800,033	6,007	1957	Gaston	NC	Lake Wylie	Open	Surface
ALLEN2	3	165	836,274	6,280	1957	Gaston	NC	Lake Wylie	Open	Surface
ALLEN3	4	265	1,704,453	7,410	1959	Gaston	NC	Lake Wylie	Open	Surface
ALLEN4	1	280	1,672,801	7,144	1960	Gaston	NC	Lake Wylie	Open	Surface
ALLEN5	2	270	1,544,858	6,674	1961	Gaston	NC	Lake Wylie	Open	Surface

Figure 2.4: Allen Unit Statistics [31]

The station sits on the shores of Lake Wylie, the oldest lake on the Catawba River (1904). The lake has a surface area of 13,443 acres, shoreline of 325 miles, and a full pond elevation of 269.4 feet [32]. The waters of Lake Wylie flow through the Wylie Hydroelectric Station, but they also support Allen Steam Station and Catawba Nuclear Station with cooling water and provide a dependable drinking water supply for the cities of Belmont and Rock Hill.

Allen's 5 steam turbines units are cooled using a once-through cooling system. The operation of the units requires an average water withdrawal of 1,225 cubic feet per second from Lake Wylie and have an associated average discharge of 1,214 cubic feet per second (implying a consumption of 11 cubic feet per second)[5] [29]. As in many OTC systems, cooling water consumption levels and water scarcity are not typically a concern in the operation of the Allen Station, even under drought conditions. However, thermal limits are a concern at certain times of the year for the Station's continuous operation.

In October of 2007, in the wake of the 2007 drought, an engineering consultancy (DTA, Inc) prepared a report for Duke Energy entitled "Carolinas Water Dependency Report" [29]. The report provided "an overview of existing Duke fossil fuel station thermal and flow constraints" and reviewed possible approaches to help minimize future generation derates by reducing vulnerability to thermal limits and a lack of water. Conclusions regarding the operational constraints for the Allen Station were as follows:

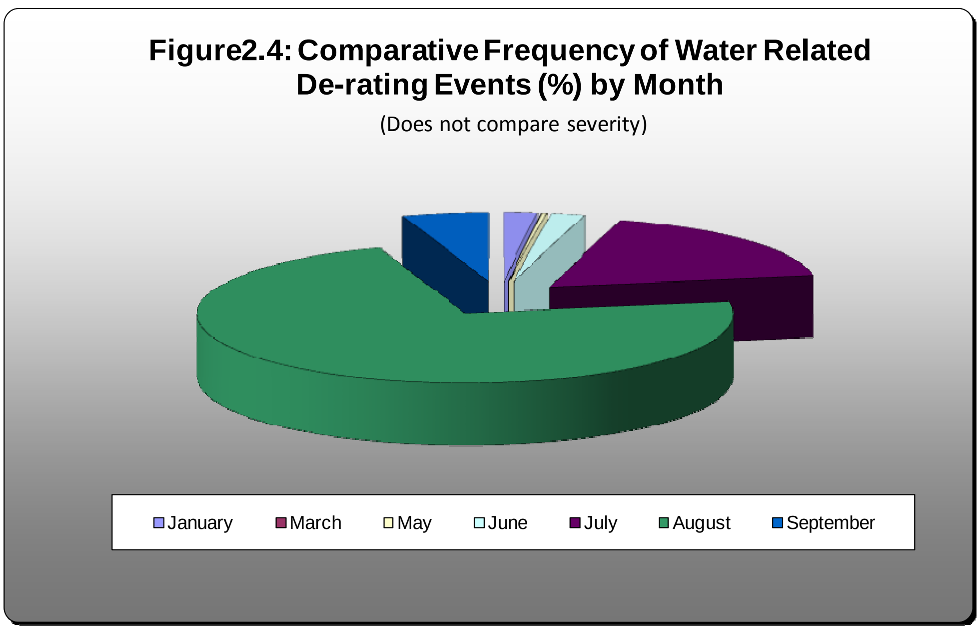
- Current NPDES end pipe thermal limits for the Allen Station are 102 degrees (June – September) and 95 degrees (October through May).
- Although the average monthly end of pipe thermal limits are some of the highest in the Carolinas, derating events can occur during extended periods that are extremely hot and dry. The most restrictive month is August, followed by July.

[5] This consumptive loss value does include the water needed for operation of the scrubbers, designed to remove sulfur dioxide and capture nitrogen oxides in emissions

- Though not a major constraint at this time, an ongoing thermal concern at the Allen Station is off-peak reductions due to high inlet temperatures, low lake levels and mild winter and hot summer conditions. In other words, though outfall temperatures are currently the primary concern, it is probable that increased water temperatures at the inlet will begin to have detrimental effects for plant efficiency and output.

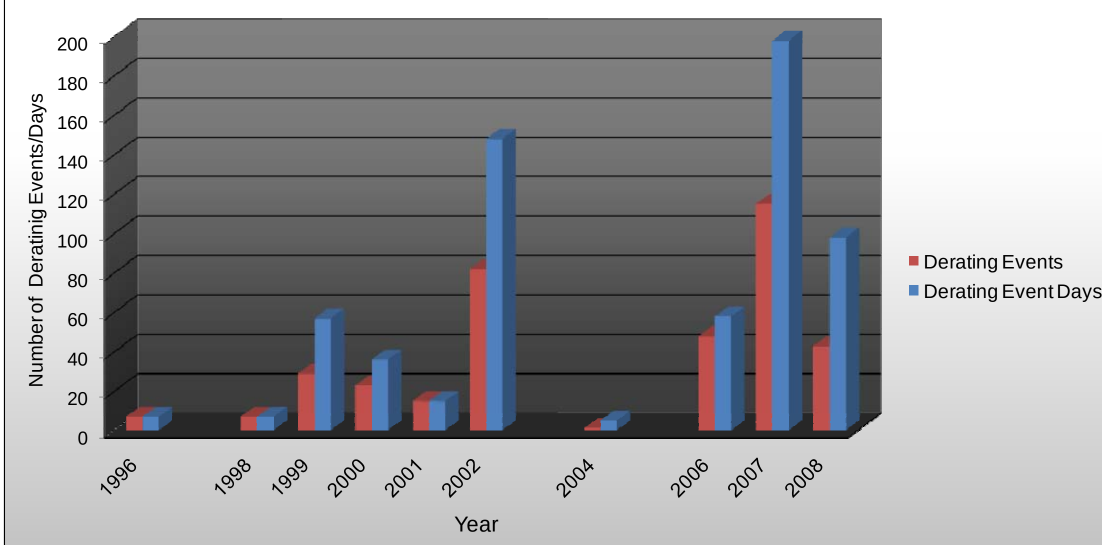
2.4.1Historical Water Related Derating Events at Allen Station

Duke Energy provided the University of Michigan team with several Excel based data sets that contained information on derating events that occurred at the Allen Station between 1996 and 2008[6]. An analysis of the data validated the findings of the DTA consultants. Derating events were more likely to occur in August than any other month (Figure 2.4). Additionally, when yearly events were compared over the 12 year period, it was very apparent that the yearly number of events was extremely volatile, as was the duration (days) of those events (Figure 2.5). The frequency of thermal derating events occurring in any given year varied significantly. For example, in 2007 over 120 derating events occurred and in 2004 there were less than 10. As a result, predicting the number of derating events on a year to year basis is very difficult.



[6] Data set was missing data for years 1997, 2003, and 2005

Figure 2.5: Annual Water Related De-rating Events and Days at Allen Steam Station (1996-2008)



2.4.2 Economic Impact of Water Related Derating Events

An evaluation of only the physical number of events as shown in Figure 2.5 is misleading to assess overall plant impact. The economic impact of derating events—the value that is ultimately most important to Duke–is a function of not only the number of derating events, but also the duration of those events (severity) and the time of day that the events occur.

$$\textit{Total Yearly Cost of Derating Events (\$)} = f(N,D,T),$$

where,

N: Number of Events,

D:Duration of each event, :

T: Time of day of each event

Recall from Section 1.4, the total cost of a derating event is expressed in the equation below where Plant A experiences a derating event and Plant B must attempt to pick up the shortfall in power production:

$$\textit{Total Cost (\$)} = [S\,(MCB - MCA)] + [L\,(Mp - MCA)] + [N\,(Mp)]$$

where,

S: Total MWh of replacement power generated at Plant B to meet system demand

L: Excess power that would have been generated over system demand at Plant A if derating events had not occurred

N: Power that needs to be purchased from the market to meet system demand because it could not be produced at Plant B

MCB: Marginal cost ($/MWh) of 1 MWh production at Plant B

MCA: Marginal cost ($/MWh) of 1 MWh of Production at Plant A

Mp: the market price of excess power at the time of event that could have been sold into the regional interconnect system

The total cost of derating events is duration dependent because the longer any single event occurs, the MWhs that have to be replaced increases and the MWhs that cannot be sold into the regional market system increases. In other words, variable S, L, and potentially N, increase with greater derating event severity. Additionally, the market price (Mp) for excess power cannot be sold into the system because the derating event is highly time dependent. The market price (Mp) shifts with overall regional demand, and significantly varies throughout any given hour or day. For example, PJM Interconnection system demand (MW) and hourly price ($/MWh) for July 15, 2009 ranged from 6,000 MW - 10,000 MW and $20 MWh to ~ $50 MWh respectively.[7]

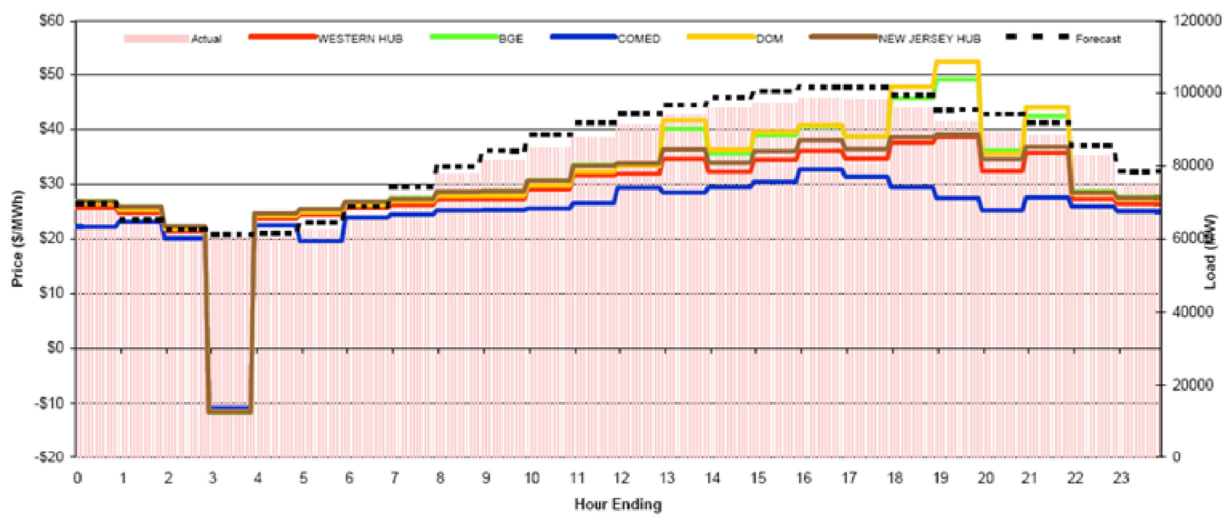


Figure 2.6 PJM Interconnect Real Time Price with Forecasted and Actual System Load for July 15, 2009 [33]

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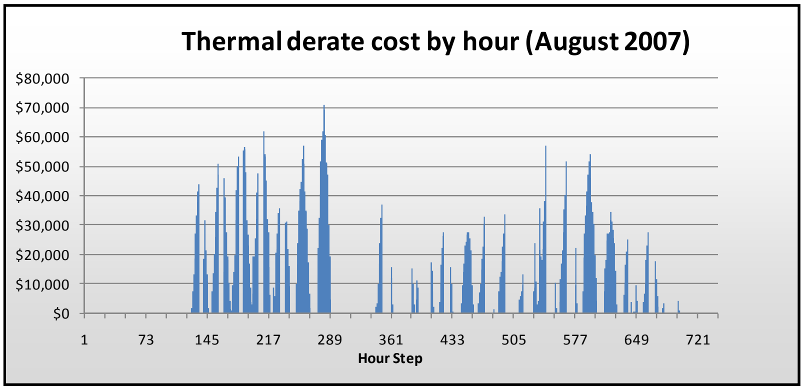
[7] PJM Interconnection LLC (PJM) is a Regional Transmission Organization, which is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM is currently the world's largest competitive wholesale electricity market [34]

Given a changing spot price for power and the need for constant monitoring of energy output, it is not an insignificant task to monitor and record the cost of derating events. In fact, Duke did not undertake this task until 2007. Duke provided a comprehensive data set of derating events in 2007 and 2008 that allowed the U of M team to calculate hourly market cost, hourly replacement cost, and severity for each derating event. The data had to be modified and some assumptions made, but the final result was a data set that contained hourly costs for all derating events in 2007 and 2008.



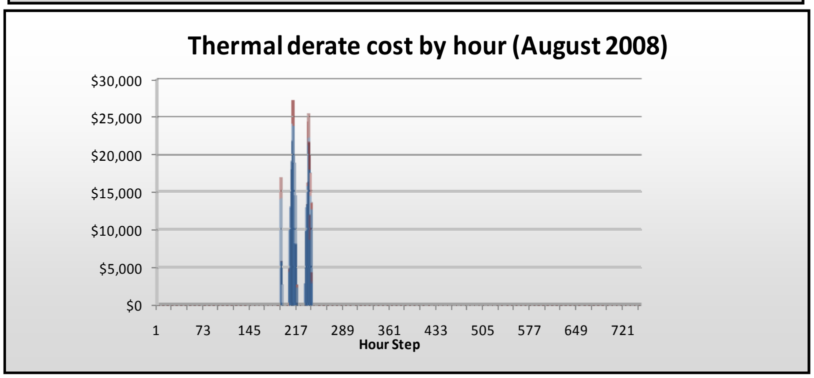


Figure 2.7: Hourly Cost of Thermal Derating Events for Allen Steam Station (August 2007 and 2008)

While the cost data set is not available for 1992-2006, the available cost data from 2007-2008 does demonstrate the significant economic impact that thermal events can have on the Allen Station. Figure 2.7 shows the water related derating costs graphed by hour in August 2007 and August 2008. In drought-plagued August 2007, the utility periodically realized economic losses of over $72,000 per hour (for a total monthly loss of $5.9 million). Conversely, in August 2008, derating events were much less frequent and severe. Costs never climbed over $30,000 per hour during events (for a total monthly economic loss of $390K). There are two important take-ways from the analysis of this cost data: 1) Water related derating events can lead to very significant economic loss; 2) Costs of derating events are extremely volatile from hour to hour, day to day, or month to month. The high level of uncertainty in yearly levels of economic loss poses an enormous challenge for management as it evaluates the company's best alternative to deal with derating events.

2.4.3 Avoided Water Related Derating Events using Alternative Cooling Technology

The high level of uncertainty in yearly levels of economic loss, coupled with the potential for a large capital investment in technology intended to alleviate economic loss, creates an enormous challenge for management as it evaluates the best alternative to mitigate derating events.

Often the first question mangers ask is "Should the power plant invest in a technology that reduces or eliminates water use and avoids costly derating events?" In years of drought, where water related derating events have been severe, the answer may be yes. Yet, in years of ample water and low temperature, the investment seems to be a poor decision. This practicum attempts to illuminate an approach that can assist managers in evaluating technology investment dynamically over time, capturing both dry and wet years and helping them to optimize investment decisions in the face of extreme uncertainty.

There is a suite of water conservation and cooling technologies available to Duke for the Allen Station. The Carolinas Water Dependency Report listed a number of possible strategies and technological options to limit thermal and flow constraints technological options [29]. Different technologies have different benefits. For example, certain technologies have:

- superior water savings,
- lower parasitic load (the energy they require to operate that is drawn from the generation facility),
- lower capital costs
- lower operations and maintenance costs
- the ability to function better in humid environments.

Finally, technologies may differ in their commercial availability in the US and will require different needs of R+D spending before full scale implementation.

In an internal presentation, Duke Energy organized the complete suite of cooling technologies as shown in Figure 2.8.

The focus of this project was not on the type of technology that could be installed at the Allen Station – thus discussion of technologies is limited in the body of this report. Rather, the purpose of the project was to demonstrate how any given technology should be financially evaluated.

Oneida Watson, a member of the U of M team, conducted an evaluation of the important parameters in technology selection and reviewed a number of the technologies. Ultimately, the team decided to evaluate a hybrid cooling system for installation at Allen Station, the Heller Hybrid System.

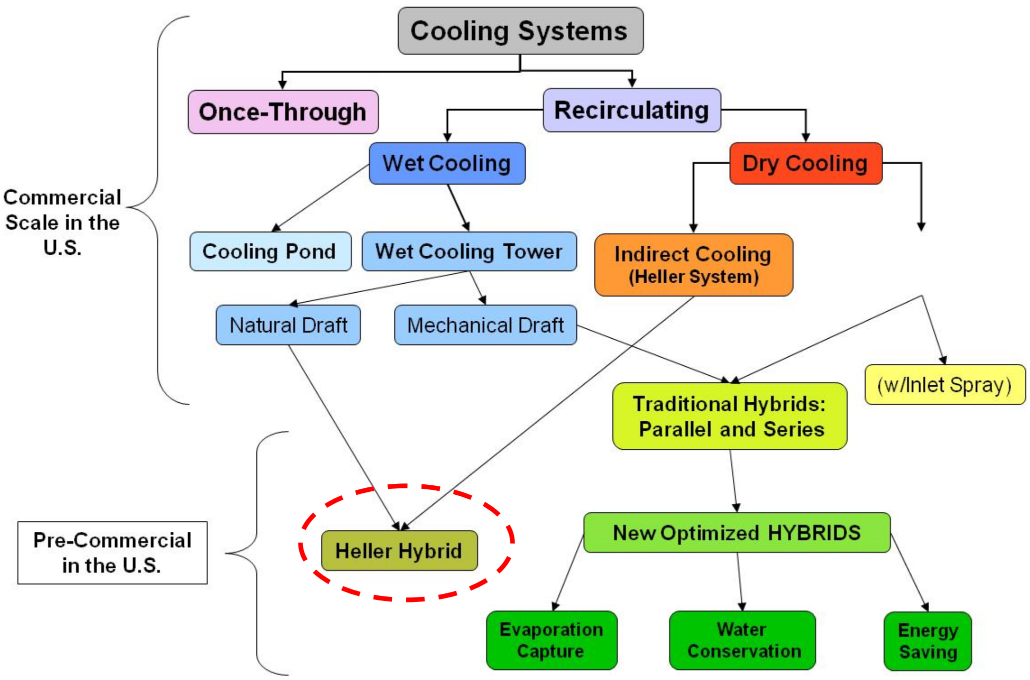


Figure 2.8: Suite of Available Cooling Technologies [12]

The Heller System ® is a combination system that uses primarily indirect air cooling via a dry cooling tower. According to the manufacturer, the system is "environment friendly, saves water equivalent to the consumption of a town of 50,000 inhabitants for each 100 MW facilitating the licensing of power projects" [Appendix A]. Heller Hybrid Systems are not commercially found in the United States, but are available for purchase by US power industry clientele. Appendix A contains a detailed discussion of the key parameters in the selection of a technology to reduce the prevalence of derating events, as well as in-depth review of the Heller Hybrid System.

Section 3: Valuing Investment in Water Conservation Technologies

The discussion in Section 2 highlights that the challenge faced by utility mangers in terms of cooling technology investment is two-fold: the frequency and severity of de-rating events in the future are unknown, and the costs associated with each event are uncertain. Intuitively, it would seem plausible that investment in the Heller hybrid system would prove beneficial because it would allow mangers to limit the cost of thermal and flow conditions while avoiding some of the disadvantages of dry cooling operations. However, due to the high capital outlay of this technological investment, traditional Discounted Cash Flow (DCF) valuation approaches may demonstrate the project to have a negative NPV. It is thus important to understand the limitations of the DCF technique. In this section we will discuss how NPV does not take into account the contingent decisions available and the managerial flexibility needed to act on those decisions [35]. In short, NPV does not take into account that a rational manager will limit downside risk. By the end of this section it should be clear how a full reliance on the DCF approach may lead to the rejection of promising projects due the approach's inability to properly value projects in uncertain environments.

With an understanding of the limitation of NPV, we introduce real options analysis, highlight our technical approach in this project using ROA, and demonstrate how ROA offers a way to address these limitations of DCF. ROA builds on a DCF approach to capture the value of options associated with projects investments. By making options explicit and quantifying their value, management is better able to make rational decisions based on more complete information.

3.1 Discounted Cash Flow Model (Net Present Value Analysis)

Discounted Cash Flow (DCF) valuation is one of the most popular techniques to valuate any project, investment, or enterprise opportunity. It used widely throughout the business and academic communities, and is one of the first lessons in any introductory finance class.

To apply NPV managers need to know four elements of an investment [36]:

1) Discount rate (which is adjusted to reflect risk level of investment)

2) Amount of the investment or cash outflows (usually these outflows are assumed to be committed even if the investment is staged over time)

3) Time period of investment/project horizon

4) The amount of cash inflows

The DCF approach uses future free cash flow projections and discounts them (often using the weighted average cost of capital (WACC), or a project specific discount rate) to arrive at a present value, which is used to evaluate the potential for investment.[8] If the value arrived at through DCF analysis is higher than the current cost of the investment, the opportunity may be a good one. In other words, if the net present value (NPV) of the investment is greater than zero than the investment should occur, if NPV is less than zero then the investment should not be pursued.

$$DCF = \frac{CF_1}{(1+r)^1} + \frac{CF_2}{(1+r)^2} + \ldots + \frac{CF_n}{(1+r)^n}$$

CF = Cash Flow

r = discount rate (WACC)

There are many variations when it comes to what can be used for cash flows and discount rates in a DCF analysis. The approach is attractive because it relatively simple and easy to understand. The purpose of DCF analysis is simply to estimate the money that will be received from an investment and to adjust for the time value of money. But, while discounted cash flow models are powerful, they do have shortcomings. DCF is a rigid and mechanical tool that is not able incorporate real world complexities of investments into the valuation. Consequently, it makes the methodology subject to the axiom "garbage in, garbage out." NPV is primarily criticized its failure to recognize management's ability to make decisions and change direction as the strategic investment evolves [37]. In order to attempt to compensate for these concerns, significant time is spent on sensitivity analysis of input variables which often demonstrate that small changes in inputs can result in large changes in the value of an investment.

In their initial "back of the envelope" valuation, Duke provided an example of the typical NPV analysis used by the business community when evaluating an investment opportunity. Duke calculated the NPV of estimated costs of water related derating events over the next twenty years at Allen Steam Station. They assumed that in any given year, there is a one-in-five chance a significant derating event occurs. Using data from the 2007 drought event, Duke calculated that a significant event results in a total derate of 189,000 MWh or an economic loss of $5.9 million. Using Excel, a spreadsheet was built to generate 1000 random simulations and calculate NPV over a twenty-year time horizon. The 1000 randomly generated NPVs per run were averaged into a single PV cost that could be compared against the capital cost of the cooling technology. If the PV cost of derating events is less than the capital cost, then the project should not be pursued. The analysis used a 7.5% discount rate. (Appendix B).

Shortcomings in Traditional Valuation Approach for the Hybrid Heller Technology

As noted above, from a traditional investment decision approach, most students of finance would conduct a traditional net present value (DCF) calculation for a given technology to determine if the firm should peruse the investment. Here we discuss several factors that are inadequately

[8] The weighted average cost of capital (WACC) is the average rate (expressed as a percentage, like interest) that a company is expected to pay to debt-holders (cost of debt) and shareholders (cost of equity) to finance its assets.

treated in the traditional DCF approach when used in the context of irreversible real world investments, such as cooling system technologies.

1) *In many real world investments cash flows are uncertain and highly volatile.* Yearly cost of Allen Station derating events could be avoided with the installation of the Heller Hybrid System.[9] However, the cash losses associated with such events are highly volatile. Duke data indicates that monthly costs can range from $0 to upwards of $6 million. This is an enormous range and it is generally unpredictable what derating costs will be in the next time period. Yet, DCF requires and assumes future cash flows to be predictable and adjusts for any uncertainty through increases in the discount rate used or through scenario analysis [38]. For example, in Duke's NPV mentioned above, 1000 simulations were generated per run of the model in an attempt to bound uncertainty.

   Furthermore, users of NPV often abuse the choice of discount rate and their choice of the becomes almost arbitrary at times. Yet, proper choice of the discount rate is extremely important because slight changes in the discount rate in an NPV analysis can have significant influence on a projects value. In uncertain environment, there may be a tendency to use higher discount rates, but the value of the project decreases with increases in discount rate. Most people do not have proper training in assessing risk and translating it into a single value.

2) *Managers exercise flexibility in timing of irreversible investment.* Managers realize that by possibly deferring investment, they can learn more about the business environment to inform their decision [38,39]. However, NPV implicitly assumes only one investment decision can be made - make the investment now, or not at all. In reality, in investment decisions, the question asked is "Should the investment be made now or evaluated again at a later date?" In Duke's analysis, they compare the calculated NPV with the current investment need, assuming that installing today or not installing at all is the only option.

3) *Risk is not uniform over time.* If we acknowledge the management can learn, has flexibility in timing, and has the ability to change course of an investment in response to changing conditions, then it is easy to see how the risk profile of an investment changes over time [39]. However, NPV approaches often use a use a static estimated discount rate (sometimes WACC) or sometimes use an arbitrary hurdle rate. In the Duke example above a 7.5% discount rate was used. Why? Most likely that is the discount rate what the analysis typically uses are was told to use by a manager, but the choice can significantly influence the model's outcome.

The shortcoming in the traditional NPV approach will often lead to an undervaluation of the investment by an analyst and therefore the project may not be pursued. For example, if an analyst

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[9] In the Allen Station Case, future cash flows are the savings associated with the prevention of derating events less any capital/O&M expenses of the Heller Hybrid System.

is very unsure about the future cost of derating events and utility markets are highly volatile, the analyst will estimate the cost of future derating events and then account for uncertainty through an increased discount rate. But, increasing the discount rate lowers the value of the project, thus projects in risky markets are penalized. As mentioned above, NPV fails to recognize that a good manager will manage the risk, be flexible, and limit the down side risk while maintain the upside. If it is the wrong time to invest, the manager will defer and perhaps invest in the next period, but he or she will certainly not close the door on the investment, as NPV assumes. The use of NPV across an industry characterized by high levels of uncertainly (oil and gas, biotech, energy, clean-tech, etc) will undoubtedly lead to an underinvestment in profitable projects - simply due to of a lack of understanding of NPV's capabilities.

It is under these conditions of high uncertainty and pending decision to make an irreversible investment before us, that it makes sense to employ the use of Real Option Analysis to supplement the results from a traditional DCF analysis. ROA is capable of modeling nondeterministic cash flows, while incorporating the value for managerial flexibility. It is also able to avoid the issue of choosing a discount rate because of certain properties associated with options theory. However, in order to discuss these properties and other benefits of ROA, it is important that we first have a basic understanding of options.

3.2 Basic Option Theory

The term "real options" is commonly used in the context of strategic corporate planning - though the notion of real options can easily be broadened to capture various types of decision making under uncertainty. The basic concept is that wherever there is an option, there is a chance to benefit from the upside, while avoiding downside risk at the same time. This idea is rooted in financial option theory.

3.2.1 Financial Options

ROA is a real world application of financial option theory. For the purpose of this paper, it is only important that that we have a basic understanding of financial options. A financial option is a contract conveying the right, but not the obligation, for the option holder to buy or sell designated securities or commodities at a specified price during a stipulated period. If the owner of the option contract has the right to buy, it is called a call option and if they have they have the contract to sell it is called a put option. One final distinction is the difference between an American and European option (Box 1). In our case, the right, but not the obligation, to invest in a technology over the life of the power plant, is

> Box 1: Option Types
>
> European Option gives the owner of the option contract the right to buy/sell the designated securities *only* on the expiration date of the option.
>
> American Option gives the owner of the option contract the right to buy/sell the designated securities at *any time* before expiration date of the option.

consistent with the attributes of the American call option. There are many other classifications of options, but these are the most prevalent and relevant for the discussion of ROA [40].

To illustrate the use and benefits of options, we provide a hypothetical example from the financial markets [41]. A stock trader, who believes that a stock's price will increase, buys an American call option on the stock rather than just buying the stock. In doing so, he has no obligation to buy the stock, only the right to do so until the expiration date. If the stock price before the expiration is above the exercise price (also called the strike price) by more than the premium (price for the call option) paid, he will profit. If the stock price at expiration is lower than the exercise price, he will let the American call contract expire worthless, and lose the amount of the premium (Figure 3.1).

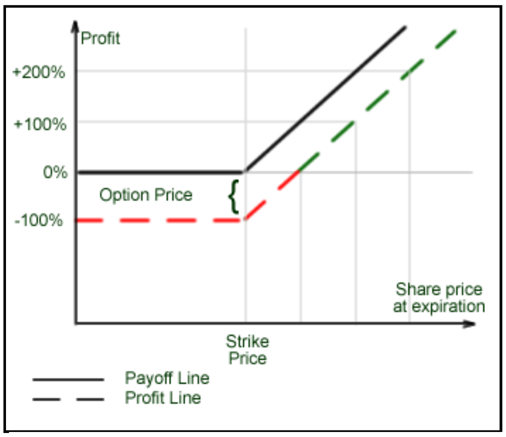


Figure 3.1: Call Option Payoff

Why would the trader have done this? The trader could have simply purchased the shares. However, by utilizing an option instrument, the trader limited his downside risk and maximized his upside profits. If the shares were to go down, the maximum amount he could lose is the option price he paid. Further, by buying the option instead of shares, he enabled himself to obtain a much larger number of options than shares for the same amount of money as if he had purchased the shares outright. Consequently, if the stock rises, he will thus realize a larger gain than if he initially had purchased shares. It is also important to note that the option would have increased in value if there were high levels of uncertainty and volatility around the stock price because the upside potential would increase disproportionally to the option price.

3.2.2 Real Option Theory

In the context the definition of a financial option, we define a real option as is the right—but not the obligation—to undertake some business decision over a given period of time; typically the option is to make, defer, or abandon a capital investment. Stated in economic parlance, a real option is the right, but not the obligation, to acquire the gross present value of expected cash flows by making an irreversible investment on or before the date the opportunity ceases to be available. Although this sounds similar to NPV calculations, and real options analysis is rooted in NPV, a real option only has value when the investment involves an irreversible cost in an uncertain or volatile environment. It is the beneficial asymmetry between the right and the obligation to invest under these conditions is what generates the option's value [42]. As we discussed above with its financial counterpart, the basic concept is that wherever there is an option, there is a chance to benefit from the upside, while limiting downside risk at the same time. Thus, there is a positive relationship between increased volatility and the value of investment.

Box 2: Types of real options that relate to cooling technology investment

Waiting option
When any key factor in the business environment is uncertain, the utility may be able to acquire higher returns (or minimize costs) by waiting for a certain period of time before investment rather than acting immediately and installing the technology. Depending on the business environment, this may also be true of hybrid cooling system. It is this option that the model evaluates, based on uncertainty faced by the utility in terms of the total cost of de-rating events over a given period as a function of the replacement cost, market cost, and duration/severity of de-rating events.

Switching Option
This option refers to the flexibility built into the technology itself. By incorporating flexibility to react to the uncertainty in the future of water temperature or availability (the ability to the wet or dry cool), the technology allows a manger to adapt to future conditions. However, the model does not explicitly "value" this option because we assume that if the technology is installed, the manager will act rationally and operate the drying cooling option when it has a lower cost than the wet cooling option. Thus, the value of this option is wrapped into the evaluation of the waiting option.

Learning Option
Though it is not done in this analysis, the analysis could be expanded to be used in the evaluation of Research and Design (R&D) or phased technology implementation under the real options framework. R&D investment is considered a "Learning option." If the technology implementation can be developed in a phased manner, the Utility can test the suitability of the technology by developing the initial phase with low costs. Based on this result, the firm can modify (or abandon) the following phase of development in order to maximize the total project value. Intuitively the concept is very simple and an idea that managers understand, but it is not incorporated into a traditional DCF approach.

We are interested in real options in the case of the Allen Steam Station because real options analysis enables a quantitative approach to modeling the impact of uncertainty, and to account for the flexibility of strategic investment [43]. ROA is not a new concept, however. Real options approaches have been applied to model the effects of uncertain climate change policy, on how to deal with emissions trading and CO2 penalties [44-47], adoption of various electricity generation technologies [48], research and development expenditures for renewables [49], technology adoption decisions under uncertainty [41,50], and investment decisions for SO2-emissions control technology [51]. Real option analysis has been shown to be excellent strategic decision-making tool in the private sector, most notably in the oil and gas sector [52].

The oil and gas sector has employed the use of ROA and invested in projects that would never have been pursued if evaluated through the lenses of NPV. For example, in a very simplistic illustration, Firm X is considering a potential investment to develop an oil field. The field can either be a dry field or a field rich with oil; and it's as likely to be one as the other. If oil is found, the investment results in project returns of $50 million. If it is a dry field, Firm X loses $60 million. An option to invest in this project is available for the irreversible cost of $10 million, which grants a 10 years lease to the offshore waters and 4 exploratory wells.

An NPV calculation, where Firm X invests now or never, values the project at 50% x $50M - 50% x $60M = $(5M). However, if the firm identifies it has an option to spend $10 million and wait and see and values this flexibility into the project (50% x $50M - 50% x $0 - $10M = $15M) the result is very different. The key in this case is that by spending $10 million now, Firm X does not have to invest in the state of the world where the field is dry. This is a very simplistic example, but it demonstrates that there is value in flexibility – $20 million dollars in this case (not taking into account discounting).

While there are many types of strategic decisions that may be made by using real options theory, we will only expand on those that are relevant to our current analysis. The oil and gas example above is an example of a learning option, but there are also growth options, abandonment option, waiting options, and switching options. The analysis of Allen Steam Station focuses on the decisions faced by a utility when evaluating an investment in water saving technologies. More specifically, the utility's option to install a hybrid cooling system in a power plant currently using a once-through cooling system is a simple waiting option (Box 2). It is a situation where a project competes with itself over time – is it more beneficial to install the hybrid technology now or wait to the next period? As an as an aside, a hybrid system is an interesting technology to consider implementing because the flexible nature of the technology results in an embedded switching option – though that is not evaluated here (Box 2).

3.3 Valuing Options

This brings us to the question "what is the value of the option?" In the financial world, how does the stock trader decide what is an acceptable price to pay today for the right to purchase a stock at a later date? Without knowing the value of the option, he cannot properly value the overall investment. Early attempts to use DCF in valuing financial options proved unsuccessful they "foundered on the appropriate discount rate to use and in calculating the probability distribution of return from an option. An option is generally much more risky than the underlying stock but nobody knows by how much" [52].

Two related financial option valuation techniques that attempt to solve the problems of option pricing are: 1) the Black-Sholes Model and 2) the binomial lattice approach. We highlight these two approaches because real options are valued using these financial option pricing techniques. However, it is important to realize that real options are often so complex that financial option pricing only provides rough valuation and staring platform and these techniques have to be adapted [52].

3.3.1 The Black-Scholes Model

In 1973, Fischer Black and Myron Scholes made a major breakthrough in option pricing valuation by deriving partial differential option valuation formula that today is known as the Black-Scholes model. It has become the standard method of pricing financial European options. Their breakthrough was based on the realization that by using the arbitrage principle and employing the technique of constructing a risk neutral portfolio that replicates the returns of holding an option, it was possible to produce a closed-form solution for a European option's theoretical price[10,11] [53]. The existence of a replicating portfolio (see foot note 4) implies that

[10] The arbitrage principle is the idea that market prices cannot allow for risk-free net profits. In other words, if two portfolios of securities (assets) have identical risk profiles they must have the same price. Otherwise, any investor would buy the cheaper of the two assts and sell the more expensive to profit from the unequal prices while maintaining the exact same risk class. [54]

[11] Construction of a replicating portfolio of an option is done through using shares in the underlying asset and risk free bonds. Prices of the underlying asset and the risk free bonds are observable in the market, the value of the replicating portfolio is known. [52]

there is a combination of underlying asset and the associated option that is risk free.[12] This realization allowed Black and Scholes and those that followed, to use the risk free rate as the discount rate in option pricing calculations. The risk free rate can be closely estimated by the interest rate on a long term government-guaranteed financial instrument like a 30-year treasury bond [52]. This is enormously important in real options valuation because users of ROA no longer need to consider the complexities of choosing the appropriate discount rate, provided that other attributes of the underlying asset are known. Simply stated, it solves that problem of risk profiles changing over time and the quantification of risk.

However, the Black-Sholes Model stops short in its ability to be useful in real options valuation because it is extremely rigid and only can solve for European call and put options, when most real options are more analogous to American options. In other words, Duke's option to install a hybrid system can be done at anytime during the life of the Steam Station. Yet, the partial differential equations of the Black Sholes Model can be utilized in a more flexible framework to solve for an option's value - this more flexible framework is the Binomial Lattice Approach.

3.3.2 The Binomial Lattice Approach

Following the derivation and concepts of the Black-Scholes model, the binomial options pricing model was developed. In the financial arena, the binomial approach models the dynamics of the option's value for discrete time intervals over the option's duration [35]. The model starts with a binomial tree of discrete future possible underlying stock prices and then a simple formula can be used to find the option price at each node in the tree. This value can approximate the theoretical value produced by Black Scholes, to the desired degree of precision. The binomial model is more desirable than Black-Scholes because it is more flexible and American options can be modeled as well as European ones. A binomial model is widely used by professional option traders and is the methodology we choose to use in our evaluation of Allen Steam Station as well.

In short, this approach evaluates options by creating a binominal lattice for a given number of time steps within the investment horizon. At each node in the lattice, the value of the underlying asset may either increase or decrease (move "up" or "down"). The up and down factors are calculated using the volatility of returns of the underlying asset. Figure 3.2 is an example of a single node binomial lattice (Note: q is the risk neutral probability of an 'up' move, 'C' is the value of the call option in either an 'up' or a 'down' move). Once all nodes have been evaluated in this manner, this approach's iterative process works backwards through the tree to the first node discounting at the risk free rate, where the calculated result is the value of the option. In this case, the value of the option is $2.38 for a call on that option.

[12] The underlying asset is the physical and financial asset to which a security holder or a class of security holders has a claim.

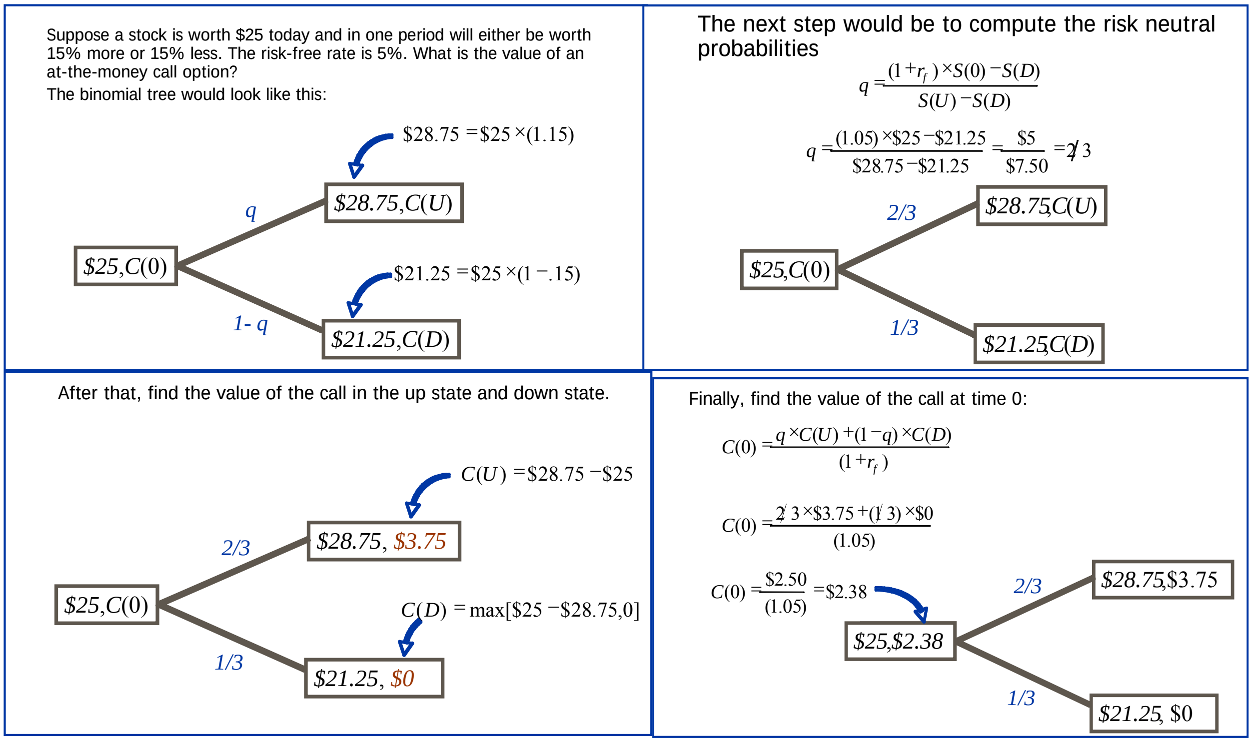


Figure 3.2: A One Step Binomial Lattice for a financial Option [55]

3.3.3 Creating a Binomial Real Options Model Approach for the Hybrid System

This section provides a general overview off the approach and methodology used in the construction of the Excel-based binomial model used in the evaluation. A more step-by-step process description of the lattice and model creation can be found in Appendix C. In order to begin an evaluation, we did the following:

First, we model the cost of the derating event in the future using the binomial assumption that the cost can go up or down in the next year. We do this for each year, stating in year 0 and going through the last year of investment horizon (year 30 in our analysis). These up/down movements (u,d) are based on historic volatility found through available derate cost data[13]. The equations for u and d are noted below.

$$u = e^{\sigma\sqrt{t}}$$

$$d = e^{-\sigma\sqrt{t}} = \frac{1}{u}.$$

[13] It is worth noting that by using the historic volatility to model our costs may result in an underestimation of the volatility of future derating events because it does not take into account future legislative events that may make derating events more costly, future changes in climate, or shift in energy markets which that would all increase volatility. A full discussion on the calculation of volatility is found in Section 4.

Using the u and d, and a "seed value" in year zero, the model populates the cost tree. In our case, we used a seed value in year 0 of $1M (Figure 3.3). The model then calculates that the expected cost of the annual derating event in Year 1 is $1,419,068 ($1M x u) and $704,688 ($1M x d). This process is repeated over and over again for each expected cost in every year. As a result, we develop a cost tree for the entire potential investment horizon with all yearly expected costs of derating events (Figure 3.2).[14]

Yealry Derate Cost For Allen Station

	Year	2009	2010	2011	2012	2013	2014
		0	1	2	3	4	5
0		($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)	($4,055,200)	($5,754,603)
1			($704,688)	($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)
2				($496,585)	($704,688)	($1,000,000)	($1,419,068)
3					($349,938)	($496,585)	($704,688)
4						($246,597)	($349,938)
5							($173,774)
6							

Figure 3.3: Annual Expected Costs in each node for Years 1-5 in Binomial Model

It is also important to notice from the equations above that d = 1/u, thus the tree is recombinant. This property ensures that if the cost of annual derating events moves up and then down (u,d), the cost will be the same as if it had moved down and then up (d,u) — it is here that the two paths merge or recombine [55]. This property reduces the number of tree nodes, making modeling more user-friendly and less complex, and thus accelerating the computation of the real option value.

Second, we calculate the risk free probabilities associated with the underlying asset (the annual cost of derating events). Recall that in financial option theory, the existence of a replicating portfolio implies that there is a combination of underlying asset and the associated option is risk free [55]. This realization allowed Black and Scholes to use the risk free rate as the discount rate in option pricing calculations. The same theory holds true for real options. We calculate risk neutral probabilities of the up movement (q) and down movement (1-q) using the following equation:

$$q = \frac{[\,(1 + rf) * S(0)\,] - S(D)}{S(U) - S(D)}$$

where,

[14] Looking at figure 3.2, it is not difficult to see that, given an "up" move five years in a row results in a estimated cost of $5.7 million cost, 30 "up moves" would result in a extremely large cost. In fact, the number would be unrealistic in that even if Allen Station generated no power, losses could not be that large. Consequently, the model caps the annual expected cost at $8 million in the cost tree.

rf = risk free rate

S(0) = 1

S(D) = u (up movement per step)

S(U) = d (down movement per step)

The up and down movement (u,d) were calculated using historic volatility. Thus, by using the risk neutral probabilities when calculating estimated costs, uncertainty has been built into the estimated costs. Therefore, the model is able to use a risk free rate as the discount factor and avoids the issue that NPV deals with in the need of an arbitrary discount rate to account for risk.

With the construction of a forward-looking cost tree and the calculation of risk neutral probabilities, we are now able to construct a model to evaluate the alternatives available to Duke. In this analysis it requires the construction of five individual cost spreadsheets and four trees that mirror each node of the cost tree (Appendix D). In the simple world of our valuation analysis, Duke faces three cases:

- Case 1: The Utility is told by a regulatory agency to install the hybrid technology at the Station in order to limit environmental impact on the Lake Wylie (Note: This is a fictional case for illustrative purposes only. This is not an actual regulatory initiative or concern at Allen Steam Station).

- Case 2: In the base period (current period), Duke has the option to either install the Technology or not install the technology. It is a now or never alternative. The case is unrealistic, however, this is how a NPV analysis views the world

- Case 3: Duke has the option in the current period to install or wait and choose again to install or wait the next period over the entire life of the plant.

In the evaluation of a project, it is important that the analysts understand the question that the valuation approach is answering. It should be clear that the valuation approach used makes a significant difference in the overall result. An analyst must be clear if the valuation technique used is from a perspective of "install today vs. never install" (Case 2) or a perspective of "install today vs. wait to install" (Case 3). The first perspective is a view that the world is a static environment (where only today that matters) and the second perspective is a view the world is a dynamic environment (Figure 3.4). Both are useful in certain circumstances

Using the static and dynamic perspectives, or lenses, we populate a number of additional trees in the model within the context of the cost future derating events and the installation of hybrid technology. This will be discussed throughout this section, but, in short, the overall objective in valuing the project from both a static and dynamic lens is to arrive at the option value of the project. And while it is possible to think of option value in isolation, it is much better to think of it "incrementally." This can be done by comparing the lowest cost static alternative versus the cost of a dynamic alternative. The static approach does not account for flexibility, the dynamic approach recognizes flexibility. Thus, the difference between the two is the "value of flexibility" – the option value.

Static Lens

First, we begin the construction of the model through the valuations of the installation of the technology using the standard NPV technique, a static view of the world, like Case 1 and Case 2.

First, we construct a spreadsheet called "Static-Install," that allows the model to calculate the present value cost of the hybrid technology were it mandated that the plant install (command and control) in the current period**.** This value is the capital cost of the technology the current period plus the PV of all future costs and losses associated with the use of the technology. Future costs include operational cost and lost revenue from the reduction in power production from the efficiency loss associated with the hybrid technology. It is assumed that water related derating events (and thus derating costs) no longer impact the plant due to the use of the technology. Using the static lens (NPV) to evaluate this alternative is appropriate because the utility has no option and must install, thus capital cost and all future operational costs are known and determined. There is little uncertainly what future costs will be, with the exception of market cost power. However, it is possible to hedge against these markets. (Figure 3.3). In this case, where future costs are relatively certain, the ROA and NPV results would be close to equal.

Second, we construct NPV cost spreadsheets to compare Dukes alternatives under Case 2's static lens. In the static view, Duke has the ability to not install or install in the current period. The utility will pursue the lower cost option of installing vs. not installing in the base year (Figure 3.3). We have already calculated the cost to install in the base year through Case 1; therefore, we create one additional spreadsheet -*"Cost_No_Install."* This spreadsheet calculates the total PV cost of not installing the technology in the base year. It utilizes the base year value from the cost tree and grows the cost at a constant growth rate and discount rate determined by the user.

This methodology is how most student of finance would approach the valuation of an investment opportunity. This approach used in Case 2 answers the question should the utilities install today or not install in the base period? However, this is not how decisions are made. Case 3, however, is a more realistic representation of a dynamic, real world investment opportunity.

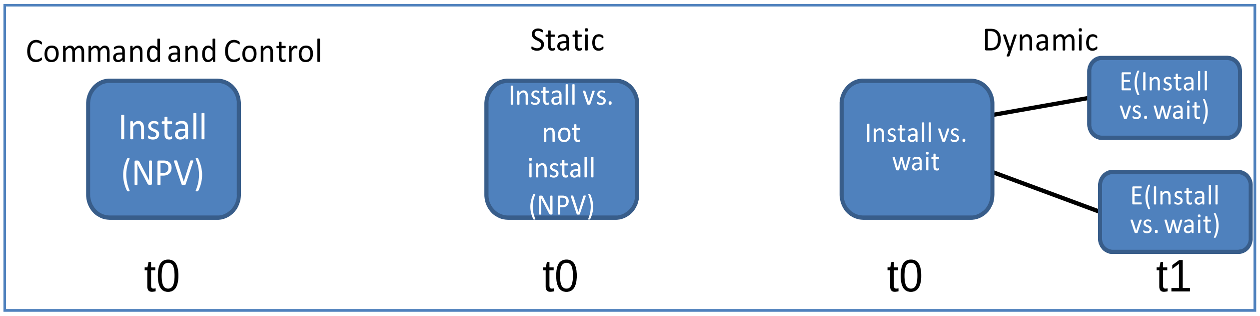


Figure 3.4: Lenses of Evaluation

Dynamic Lens

The second lens is a real options lens, a dynamic lens, *where we evaluate and compare the expected cost of waiting against the expected cost of installation in every year at every node in the future (Case 3)* (Figure 3.4). The cost of installation accounts for capital costs of installation at that node, plus the current period and all future costs associated with use of the hybrid technology, such as operation cost and efficiency loss cost. However, in order to allow the comparison of the cost of waiting vs. cost of installation, we must construct three additional spreadsheets and 2 additional trees. These include:

- *"Option 1" Spreadsheet:* This spreadsheet calculates the cost of not installing for a single year in for every node. In other words, paying the cost associated with derating events. This spreadsheet calculates the cost of not installing using the corresponding year and node from the Cost Tree.
- *"Option 2" Spreadsheet:* This spreadsheet calculates the cost of having the hybrid installed for a single year for each node. The value in each node is the increased operations cost associated with installation of the hybrid in that year. It does not account for capital cost of the installation. Capital cost are kept separate in figuring out the technology valuation, keep the cash flows from sale of allowances less any variable costs separate from the installation costs (net of PV of depreciation tax shield of course). This is because it is consistent with the notion of an option: the value of an option comes from the savings (less any variable costs), while the installation cost (net of PV of depreciation tax benefit) is like the strike price [56].
- *"Capital Cost" Spreadsheet:* This spreadsheet calculates the total PV cost of hybrid installation in each year. The user inputs allow for the capital cost to change over time. A user input inflation rate affects the capital cost over time, as well. The total PV capital cost is a function of total capital outlay in the year of installation less the tax affect of deprecation over the depreciation schedule.

Using the NPV spreadsheet "Option 1" a macro populates a tree, we call "Tree 1." The values in Tree 1 are the cost of no installation for a single year in each node – to be clear, no future costs are taken into account

Using a NPV spreadsheet "Option 2", the marco populates a tree, we call "Tree 2." *The values in Tree 2 are the cost associated with installation for a single year in each node – once again, there are no future cost incorporated.* It is important to note that this cost tree ignores the capital cost of installation. Thus, the cost in Tree 2 only represents the increase in operational cost in a given year, if the hybrid is installed in that year.

With these two tress constructed, we can begin to construct a dynamic evaluation of the cost of the potential hybrid investment. First we construct Tree 3. *At each node in Tree 3 is the cost of having the hybrid installed in that year and all future years – still capital costs are left out of the cost in this tree.* Because of uncertainty around the future costs associated with use of the hybrid technology, you would need to use the model to determine the current and future costs associated with use of the hybrid technology. The mechanics in the construction of Tree 3 are the following:

- The value for each node in the terminal year of the investment horizon is the same as the value for each node in the terminal year in Tree 2. This is true because we assume that if the hybrid is installed in the last year of plant operation, it will be used for one year and then scrapped, this there are no future operational costs.

- With the terminal values known, the model back populates nodes for the previous year, and then the previous year, and so on, until the base year is reached. The model populates of each node in Tree3 using the following steps:

    1) The model finds the value from the corresponding node in Tree 2

    2) To the value from Tree 2, the model adds the future cost of using the hybrid technology. The future cost of using the hybrid technology is the value for the up node in the next period multiplied by the risk neutral probability of the up case (q) plus the value for the down node next period multiplied by the risk neutral probability of the down case (1-q).

    3) This sum is then discounted back one period by the risk free rate and steps 1-3 are repeated in backward and iterative manner through the entire tree.

Since the model starts at the terminal node (at the end of the investment horizon) and work its way back, each node in Tree 3 gives you the lifetime operational cost associated with using the hybrid technology if it were installed at that node (capital costs are still absent).

With Tree 3 constructed, the model moves to evaluate the estimated total overall cost of investment. This value includes not only the cost associated with the installation, but also the cost of waiting. The cost of waiting is a bit complicated. This cost can be thought of in two parts:

- First, the cost of not having the system installed in the current node is easy to calculate as it equals the cost of derating events in the current node that are found in the Cost tree.
- Second, the cost of waiting also needs to account for future costs and the future costs are more difficult to calculate as they are the weighted probability of the costs associated with the decisions you make in all future years; at every future node you must once again decide to install or wait. *Thus, unless the technology is installed in Year 1, future costs are a combination of derating costs and technology installation and operation costs. To calculate this cost, the model constructs another tree, called "Tree 4,"* and once again starts at the terminal year and work its way back. The process is as follows:

    1) At each terminal node the model chooses the lowest cost option between:

        a. Not installing (Tree 1) and

        b. The cost to have the hybrid technology installed today and in the future (Tree 3) plus the net cost of installing the hybrid (the capital cost of instillation less the depreciation tax credits) (located in the "Capital Cost" Spreadsheet).

       The lowest cost value is populated into the terminal nodes of Tree 4

    2) For each previous node, the model takes the cost of installation (net capital costs of installation at that node), plus all current and future costs associated with use of the hybrid technology (Tree 3)).

    3) This value calculated in Step 2 is compared to the cost in the current year of doing nothing (Tree2) plus the sum of the value for the up node next period times the risk neutral probability of the up case (q) plus the value for the down node next period times the risk neutral probability of the down case (1-q) and finally discounted back one period by the risk free rate.

Once again, because you start at the end and work backwards, you end up with the lowest cost of compliance in a case where you can make an installation decision at every node. The value in the first node (the base year) of Tree 4 is the dynamic valuation of the investment opportunity which takes into account managerial flexibility under uncertainly.

Finally, the model calculates the difference between the value in the first node of Tree 4 and the lowest cost alternative between the PV cost of not installing the technology in the base year and the PV cost of installing the hybrid system in the base year. This calculated difference is the option value of the investment.

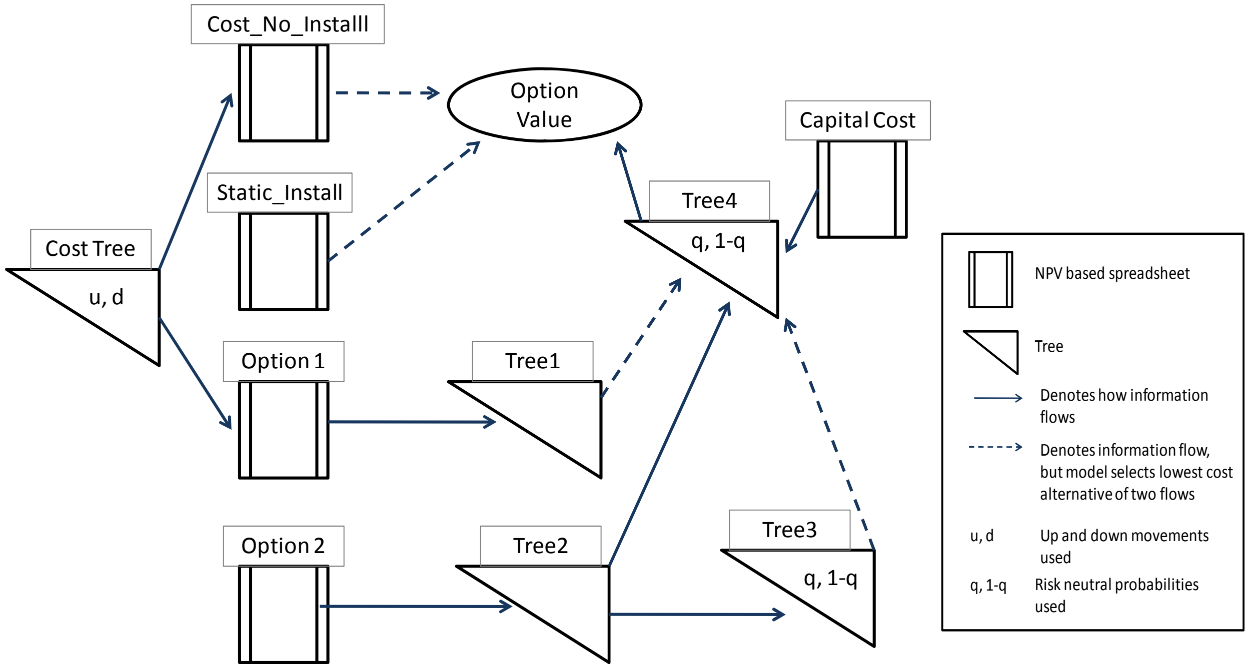


Figure 3.5: Flow Diagram of Model Construction

3.4 Does ROA seem complex?

Clearly, this methodology is more complex than the DCF/NPV approach. ROA requires calculation of both the static and dynamic values and an understanding of the relationship between different views of the world, and the associated options. However, the usefulness and accuracy of the final results, specifically the dynamic value and the option value, warrants the additional complexity - as the results add valuable information to managers analysis that is absent if only an NPV approach were pursued. Furthermore, if the methodology that is described this section is carefully scrutinized, it is apparent that for an ROA, managers need to only know five key elements about the investment opportunity to construct a model like the one described above [36].[15] These elements are:

1) The risk free rate

2) The amount of the investment that can, but not does not necessarily have to, to be made at the conclusion of the next time period – this is equivalent to the exercise price in a financial option

3) The time interval before the next investment decision must be made and capital outlays undertaken – equivalent to time to expiration in an American option

[15] There can be numerous model specific variables and inputs that are needed (See section 4). However, all ROA models will share these 5 elements.

4) The present value of the cash flows or savings - this is the value of the underlying asset

5) The volatility, the measure of how uncertain the future value of the opportunity is (based on the underlying asset).

Recall, in section 3.1 we listed the 4 elements a manger needs to know to conduct a NPV analysis. To review these elements needed for NPV are: 1) Discount rate, 2) Amount of the investment or cash outflows, 3) Time period of investment, 4) The amount of cash inflows [36]. While there is a fifth element needed for ROA (volatility), the value of each element is more easily defined by the user than the elements needed for NPV in cases of uncertain environments, in particular the discount rate. Furthermore, ROA's elements and approach allow the model to account for managerial flexibility in project valuation, which provides a more accurate valuation of the overall investment

While the computation and excel coding in the model do take time, the most difficult step of ROA is initially realizing there is an option to value and determining the best framework to evaluate the option. What is the underlying asset? Can I measure its volatility? These are two critical questions that are addressed in Section 4.

Section 4: Real Option Model Parameters

The binomial approach provides an initial framework for the construction of an ROA analysis. However, the analysis still requires the analyst to engage in critical thinking to tailor the framework and develop the parameters to fit a real world complex problem. The challenge of taking a real world complex problem and placing it into a mathematically-based model originally intended for the valuation of financial options is a hurdle in ROA [57]. It is perhaps the most difficult aspect in approaching investment opportunities as real options, and an often cited reason for the lack of ROA's widespread use. There is academic literature that approaches this subject and attempts to simplify frameworks for real options analysis. For example, Timothy Luehrman wrote an article for Harvard Business Review which established a correspondence between investment project characteristics and the five variables that determine the value of a simple call option on a share of stock (Figure 4.1) [57]. He then attempted to create a methodology that allowed a user to integrate a Black Scholes approach to ROA into a traditional DCF spreadsheet and analysis – calculating a "modified NPV." However, the problem with Luehrman's methodology lies in his overall objective.

Investment Opportunity	Variable	Call Option
Present value of a project's operating assets to be acquired	S	Stock price
Expenditure required to acquire the project assets	X	Exercise price
Length of time the decision may be deferred	t	Time to expiration
Time value of money	rf	Risk-free rate of return
Riskiness of the project assets	σ^2	Variance of returns on stock

Figure 4.1 Mapping and Investment Opportunity onto a Call Option

In his research, Luehrman showed how a corporate analyst could use these five corresponding project variables to produce a quantitative output that could be used repeatedly in project valuation and was compatible with traditional DCF capital-budgeting spreadsheets. This is a very attractive proposition – an incorporation of real option valuation into a traditional DCF framework and a simple "plug and chug" methodology. We would encourage everyone interested in this subject to read his paper. However, while this five-variable framework is an excellent way to help people grasp the relationship between option theory and real investment projects, trying to place a real option dynamic solution into a linear DCF equation to calculate a “modified NPV” is problematic because real word investment do not conform to static or inflexible models. It is also why the Black-Sholes Equation is often not used in ROA [36]. While stocks have clearly defined standard variables on which they are valued, the complexity of a real world projects, combined with each project’s unique circumstances, require a critical assessment of input variables and a flexible model. It is for this reason that that a binomial option was used to build a ROA analysis around the option to install the Heller Hybrid System at Allen Steam Station.

4.1 Parameters and Inputs

The use of the binomial model requires a solid understanding of real options theory, a critical eye towards available options and alternatives, and how those options affect the path of the project. While it can be time intensive to establish the framework, define the important parameters and inputs, and build the binomial model, the result will be a more robust, more accurate and more flexible model than a “cookie cutter” approach to ROA. Two of the most critical parameters in any ROA are the underlying asset and the associated volatility.

4.1.1 Underlying Asset

In financial option theory, the underlying asset is defined as “the physical and financial asset to which a security holder or a class of security holders has a claim” [58]. In the valuation of the financial option, determining what is the underlying asset is not an issue. It is known – it is the security on which the option is being purchased. However, in real option valuation, determining the underlying asset can be unclear. We first must define the option.   But then we must determine which underlying variable most captures the value of that option. What should be modeled? The most important characteristic of the underlying asset is that it must capture majority of the project’s uncertainty. Recall that if there is no uncertainly associated with underlying asset, then real option is worthless because the future is known and predictable. The calculation of uncertainly in the business environment is discussed at length in Section 4.1.2.

In the Allen Steam Station analysis, we spent significant time early in the project determining the most appropriate value to define as the underlying asset. In real option valuation, one is often influenced to define an underlying asset based on the most readily available information. This was the case in this instance, as well. Initial definitions of the underlying asset were:

- the loss in power from water related derating events per period (MWh),
- the shortfall in volume of water demanded in a given period.

However, each of these proposed “underlying assets” had their problems. For example, by defining shortfall in volume of water demanded in a given period as the underlying asset, we would have modeled how the hybrid system would affect overall water availability. This was an attractive variable to model because we had 12 years of water related data and information

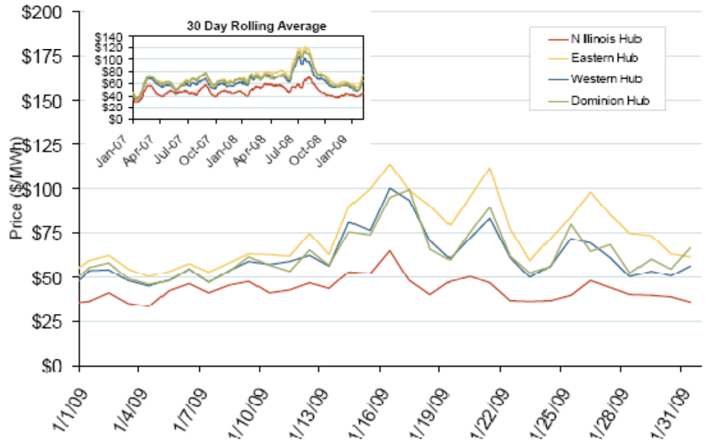


Figure 4.1: Daily Average of PJM Day-Ahead Prices [33]

regarding MWh lost due to water derating events. However, this approach has several shortcomings. While it would have captured the uncertainty associated with the frequency and severity of the derating events (climatic uncertainty), it ignored uncertainty of the energy markets (PJM Energy Market) and the variable costs of production at power plants that would have been used to replace power during derating events (Figure 4.1). Consequently, it would have been necessary to independently model future prices and production costs to capture the economic impact to Duke Energy and properly evaluate the option to install a Hybrid System. This effort would have been complex and required a working knowledge of Monte Carlo Simulation and Geometric Brownian Motion; it was impractical to assume that your standard corporate budgeting group would take the time to engage in such an effort [48].

For the U of M team, it was necessary to think through the underlying problem at Allen Station in order to properly define the underlying asset.   The line of thought followed the Figure 4.2. The region's climate, which is innately unpredictable, influences water temperature and water volumes; derating events occur because of changes in water temperature and water levels, and result in reduced power. Reduced power impacts Duke Energy in two ways – 1) they have to replace or make up the power at another plant where production costs are higher or 2) they are unable to sell their power into the regional energy markets (which are uncertain).   Thus, if we could sum the replacement cost and market cost of derating events over a period we would capture the climatic uncertainty and the market price uncertainty in a single variable. We defined this variable as the underlying asset – the cost of water-related derating events or the "value" of water. Fortunately, Duke had recorded the market prices, replacement costs, and duration of derating events on a hourly period for 2007 and 2008.

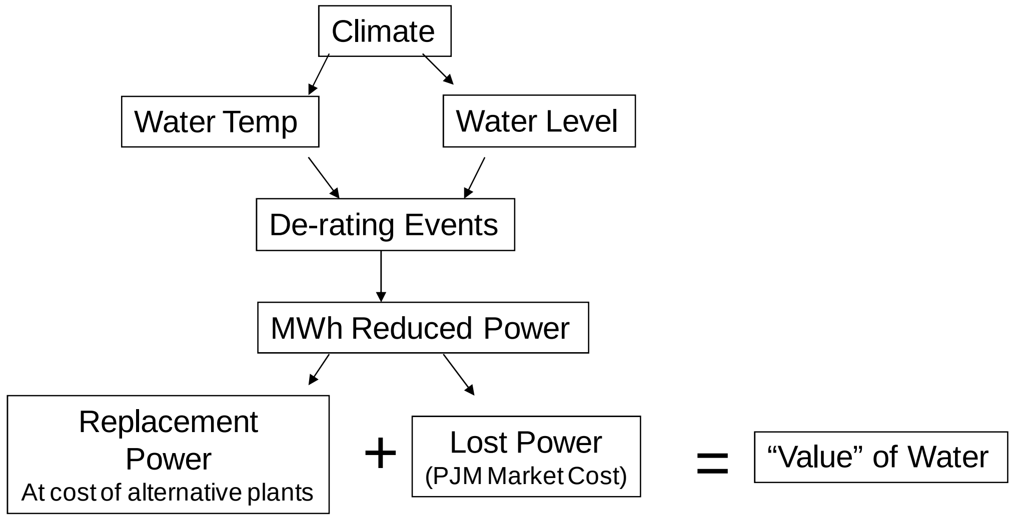


Figure 4.2 Defining the Underlying Assets

4.1.2 Cumulative Volatility

Volatility is a key component in a ROA because it a source of considerable value when options exist. In a real world investment decision, it is plausible that while we are waiting to make a decision, the underlying asset value may change, ultimately affecting our investment decision for the better [57]. However, this possibility is difficult to quantify because we are not sure that the asset value will change or, if it does, what that change will be. Fortunately, we don’t have to measure added value because we can measure uncertainty and then let the ROA model quantify the value [55].

In order to measure uncertainly, one must first assess probabilities associated with the underlying asset, in this case the cost of derating events. One of the most common probability weighted measures of dispersion is variance, (σ2). Variance is a summary measure of the likelihood of drawing a value far away from the average value in the pot. So, in the Allen Station case, a derating event of $3M would have a specific variance based on a suite of historical costs of derating events. However, while variance is an excellent measure of uncertainly in the case of real option valuation, it is incomplete because real options have a time dimension to them [57]. Uncertainty is impacted by the decision to wait to install a project in 2 months vs. two years. In option valuation, it is important think in terms of variance per period. In our case, a period was one day of calculation of variance. Therefore, the total amount of uncertainty is the variance per period multiplied over the total number of periods, or σ2t.

One final consideration in determining a measure of uncertainty is the units in which the model reports volatility. In our example, we are concerned with the uncertainty of the annual cost of derating events, measured in dollars. Variance, σ2, is measured in square units, or in this case, dollars squared. This is intuitively difficult to grasp in a meaningful way [56]. Therefore, it is helpful to express uncertainty in terms of standard deviation rather than variance. Standard deviation is simply the square root of the variance and it has the advantage of being denominated in the same units, dollars, as the variable being measured. Thus, the square root of the cumulative variance (σ2t) is equal to σ√t, also known as cumulative volatility.

The Triangular Distribution

In financial option valuation, volatility is calculated from the returns on an index or stock price. Historical data on returns is readily available through a number of electronic databases and websites. However, in the case of real options, you cannot necessarily assume that comprehensive datasets that track the value of the underlying asset are available. Yet, the ability to determine an appropriate cumulative volatility is dependent upon reliable and representative data. If such data exists, calculation of a volatility value for use in a ROA is a straight forward calculation that is learned in an introductory statistics book. However, what if comprehensive time series data is lacking for your specific underlying asset? In the case of the Allen Steam Station, the U of M team only had data available for 2007 and 2008. Furthermore, because 2007 was a drought year, it can thus be assumed that water related derating costs would have been extremely high in that year. As a result, a lack of data made it impossible to construct a full distribution and model cumulative volatility.

The triangular distribution is a widely used distribution in simulation analysis and often called upon in cases where data is limited and little is known about the probability distribution [59].

Instead, we chose to use a basic triangular distribution to estimate volatility. The triangular distribution is a widely used distribution in simulation analysis and often called upon in cases where data is limited and little is known about the probability distribution [59]. With only three parameters, it is possible to estimate volatility through use of the triangular distribution. The three parameters are:

1) The minimum value in the data set (Min)
2) The Maximum Value in the data set (Max)
3) The most frequently occurring value in the data set (Mode)

Distributions are not necessarily symmetric. In fact, it is likely that the distributions are skewed left or right. Figure 4.4 provides visual representation of three types of distributions: Symmetric, skewed left, and skewed right.

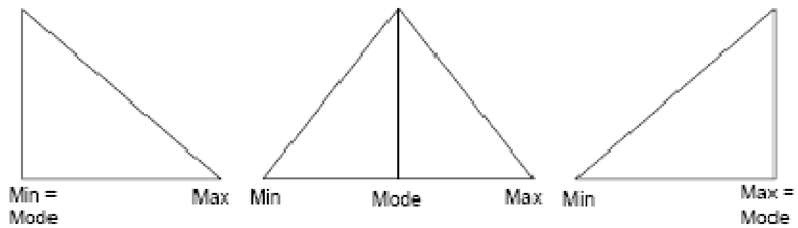
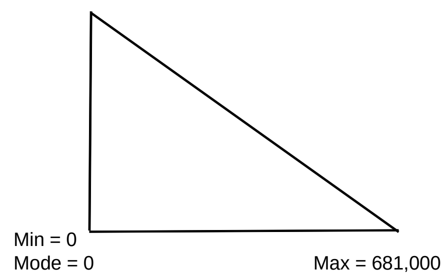


Figure 4.4 Different forms of Triangular Distributions [59]

In the case of the water related derating costs at Allen Station in 2007 and 2008, the data showed that Duke realized a maximum of $681,000 in economic loss per day and a minimum of $0/day (days in which no derating event occurred). Most days no events occurred, thus the mode was $0 as well. Because MODE = MIN, the triangular distribution is left skewed (Figure 4.5). We calculated a standard deviation of approximately 50%. This is very large, and given that the value was calculated using only two years of data it should be used with caution. However, standard deviations of "similar" highly idiosyncratic industries like biotech, cleantech is typically this magnitude or higher (56). In the actual analysis, a more conservative 40% cumulative volatility was used.



$$\text{VAR} \quad \frac{a^2 + b^2 + c^2 - ab - ac - bc}{18}$$

where a = MIN, b=MAX, and c = MODE

Figure 4.5: Triangular Distribution of the Cost of Derating Events at Allen Steam Station

4.1.3 Other Inputs

Each ROA model that an analyst constructs must include a defined underlying real asset and a calculated/assumed cumulative volatility. In addition, to the five elements needed in every ROA highlighted in Section 3, there are numerous other inputs that are required in the calculation of a real option value that are specific to the underlying asset in question. The inputs required to calculate an option value in this specific case are listed and briefly commented upon below. It is important to note that the purpose of this practicum was to demonstrate the usefulness of ROA in evaluation of a technology at Allen Steam Station. Consequently, from an engineering perspective, the model is somewhat simplistic. There were inputs and value that were ignored; these would need to be considered in a full scale evaluation. Figure 4.5 provides a screen capture of the model input user interface.

Global Inputs

- *Nominal Discount Rate:* The time value of money in the model and used for static NPV calculations

- *Base Year:* Tells the model the year in which dollars should be reported, as well as informs the model of the current year for use in the static alternative calculations

- *Life of Option:* Tells the model the length of the option period (years) from the base year and the total length of the evaluation period

- *Risk Free Rate:* Used in calculation of the risk free probabilities and discounting over the investment horizon

- *Up and Down Movements of Underlying Asset:* Calculated using historic volatility, these values used in the population of the Derate Cost Tree

- *Risk Free Probabilities:* Risk neutral probabilities are calculated using the up and down moments of the underlying asset (u,d). Thus, when calculating estimated costs throughout the model using the risk free probabilities, uncertainty has been built into the estimated costs. This allows the model is able to use a risk free rate as the discount factor and avoids the issue that NPV deals with in the need of an arbitrary discount rate to account for risk.

- *Number of Steps per Year:* This value informs the model of the time period over wish the volatility and up down movements should be calculated. We evaluated the derate costs on an annual basis (1), but we could have just as easily evaluated it over any time period. For example, if we had evaluated over a daily period (input in model of 365), each node would have represented a single day instead of year. While the increased granularity from using daily nodes would result in marginally more accurate results, the trees become extremely large and it is difficult for Excel to handle the file size.

- *Effective Tax Rate:* Used in equations to populate trees when adjusting for losses and profits in any given year through standard NPV techniques and populate Trees

- *Seed Value for Derate Cost Tree:* Initial value needed by model to populate Derating Cost Tree using "u" and "d"

<u>Base Case Inputs</u>

- *Nominal Growth in Derating Costs Per year:* Because derating costs are related to replacement and market costs of energy, increases in the value of energy translate in to increased costs to the utility if they are unable to deliver that power due to derating events. Market value for energy has generally increased over time, pushed upward by demand.

- *Annual Costs associated with a Business as Usual Strategy:* This value is ignored. From an engineering perspective, there would be costs associated with a do nothing strategy. Changes in water temperature entering the system and an erratic curtailment of the system can result in increases in fouling and the need for maintenance.

<u>Alternative Inputs (Technology Case)</u>

- *Capital Cost of Technology:* The capital cost of the technology is the equivalent to the exercise price of a financial option.

- *Yearly Increase/Decrease in Cost of Technology:* The capital cost of technology does not remain constant over time. Technological advancements typically drive the cost of current technology downward as improvements are made in the technological arena. The model allows for straight line increases/decreases for technology capital costs.

- *Rate of Depreciation per Year (Straight line*): Indicates the rate of yearly depreciation for the capital investment for the technology installations

- *Increase in Operating Cost per Year:* At the installation of the new technology, the user can indicate an increase in O&M costs. The model assumes that increased yearly O&M cost due to technology installation is constant from year to year

- *Average Efficiency Loss with Technology Installation:* The installation of certain types of cooling systems results in loss in overall system efficiency. This translates into a reduction in total MWh generated and a loss of profit. The Heller Hybrid system results in approximately 1% efficiency loss (Appendix A).

- *Revenue and Cost per MWh Generated:* The model assumes a constant cost of production per MWh and constant revenue per MWh. The difference in the two values is the profit per MWh. Profit per MWh is used to monetize the 1% efficiency loss associated with the Heller Hybrid System.

4.2 Model User Interface

The model contains an interface where the user can manage and view the input values to the model. Input cells are coded by color.

- Yellow cells are inputs to be changed and managed buy the user.
- Orange cells are calculated by the model based on user inputs and should not be changed by the user.

- Green cells are reference cells for the model that are populated by the model's macro using values from the Derate Cost Tree.

Figure 4.6 shows the model interface as it is viewed in the model with the inputs used in the final analysis by the U of M team. Results from the model run can be found in Section 5.

Figure 4.6: ROA Model User Interface

Shared Inputs	
Macro	
Discount Rate	7.0%
Base Year	2009
Total Life of Option	30
End of analysis Horizon	2039
Risk Free Rate (effective)	5.0%
Effectve Tax Rate	37.7%
Total Cost of Annual Derating Events in Evaluation Year (value of Underlying Variable)	($1,000,000)
Seed Value for Tree	($1,000,000)
Annual Standard Deviatiton	40%
Type of Option	American Call
Base Case Inputs	
Growth in Derating Event Costs per year (nominal)	8.0%
Year Derate Event Annual Cost Inputed	2009
Average MWh Production per year from Plant (Mwh)	7,000,000
Increased O&M Costs	30,000,000
Technology Case Inputs	
R+D funds needed?	X
Yearly spend in R+D	X
Total years of R+D spending	X
Year Technology Installed	2009
Year Technology becomes Operational	2009
Capital Cost	($39,000,000)
Real Yeary Increase in Cost of Technology Installation	3%
Rate of Depreciation per year	5%
End of deprec. Period	2029
Increased Operating Cost (per step)	$ 30,000.00
Average Efficiency Loss with Instalation	1.0%
Revenue per MWh	$ 42.00
Unit Avg Cost of MWh	$ 37.00

Probabilities	
Up movement per step (S(U))	149.2%
Down movement per step (S(D))	67.0%
Annual risk free rate (stated)	4.88%
Number steps per year	1
Risk free rate (per step)	5.00%
1 + Risk free rate (per step)	105.00%
Risk neutral probability (up) (q)	46.2%
Risk neutral probability (down) (1-q)	53.8%

R+D is an option in itself. Staged spend.
but not modeled in

Section 5: Model Results and Discussion

The major challenge in creating a ROA model that provides relevant results was two-fold:

1) The challenge of framing the investment question in way that an ROA model can evaluate it and defining the underlying asset that should be evaluated.

With the underlying asset defined, the challenge is having enough data and data in a usable form, to determine historical volatility and then use this value in modeling future cost trees.

These barriers in development of an ROA for the Allen Steam Station case were significant and took considerable time to overcome. Additionally, through this analysis we realized that, while it is nice to think of option value in isolation, for modeling purposes it is much more useful to think of the option value "incrementally" [56]. An incremental approach allows us to compare the lowest cost static alternative against the cost of a dynamic alternative for a project that competes against itself over time to derive the option value.16 The incremental approach is easier intuitively to someone with no background in option valuation and computation is less complex when compared to an approach that calculates the option value in isolation

With these hurdles overcome, the construction of the model consisted of a series of formulas, excel coding, macros, and a range of steps, some simplistic and some semi-complex, that were summarized in Section 3, Figure 3.4. Finally, with the model constructed and input values determined, results were generated.

5.1. Model Outputs

The model results provide the user four important values:

- The present value of the static alternative
- The present value of the dynamic alternative
- The option value
- The command and control alternative

The Static Alternative

Recall from Section 3.3.3 that the model is interested in lowest cost alternative between the PV cost of not installing the technology in the base year and the PV cost of installing the hybrid system in the base year. In the Case of the Allen Steam Station, because the technology is so expensive, installation in the base year will never occur. Thus, generally the PV cost of not installing the technology in the base year will be the lowest cost alternative. Given the model inputs, the PV cost of the lowest cost static alternative, is $22.3 million.

[16] A project that competes against itself asked the question, "Is it better to wait to invest or to invest today" and this over and over again for the project over the investment period.

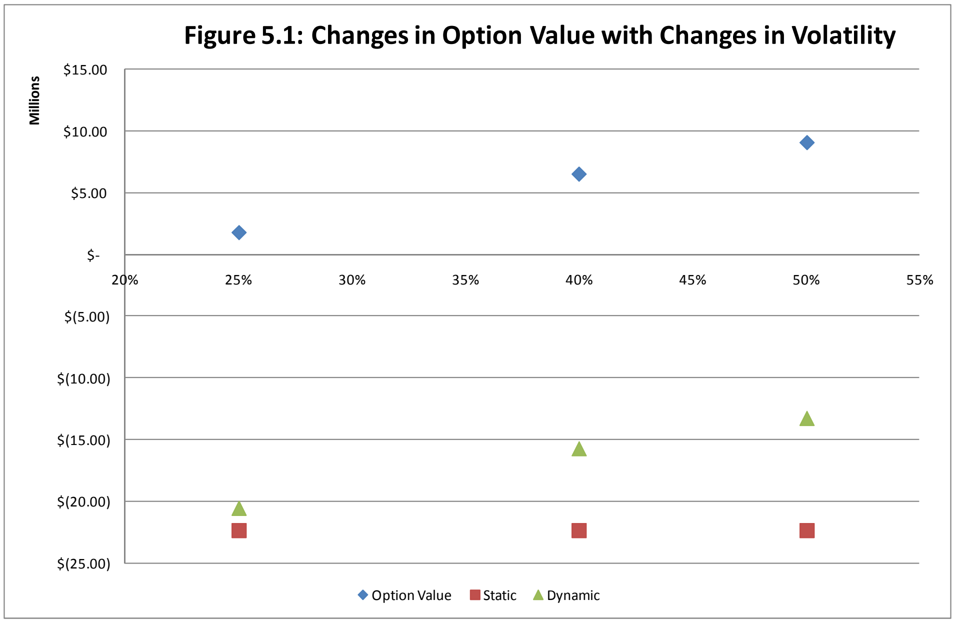
The Dynamic Alternative

Recall that the dynamic alternative is where we evaluate and compare the expected cost of waiting against the expected cost of installation in every year at every node in the future through a backwards iterative process until we arrive at the node in base year of Tree 4. The value in the first node of Tree 4 is the dynamic valuation of the investment opportunity which takes into account managerial flexibility under uncertainly. The expected PV cost of the dynamic alternative, under the model inputs, is $15.7 million.

The Option Value

As previously stated, we can calculate the option value as the incremental difference between the lowest cost static alternative and cost of the dynamic alternative. If this difference is not zero, it indicates that there may be a discrepancy in the value of the project using the PV of the static alternative rather than the PV of the dynamic alternative. Using the static and dynamic values mentioned above, the results demonstrate that in this case, where this project is competing against itself over time and a manger is in a position to exercise flexibility of when, if ever, to install a technology, the $6.6 million (the difference between the static and dynamic alternatives) represents the valuation deficit that a project suffers if it evaluated using a standard DCF/NPV approach. Systematic use of NPV has undoubtedly led to an undervaluation of technology and perhaps an underinvestment in technology in highly uncertain environments.

Figure 5.1 shows that the increase volatility results in an increase in the option value. Increased levels of volatility place increased importance on mangers to exercise managerial flexibility and alter the course of the future based in future information. The table visually illustrates that when uncertainty is involved, managerial flexibility is important in structuring project analysis, and is often the source of additional value in the decision [37]. Notice that the static value does not change because DCF analysis ignores volatility in the calculation of NPV.



The Command and Control Alternative

Although a command and control alternative was not a focus in the model, the team considered it an interesting value for comparison. This alternative represents a government policy forcing a power plant to install a water conservation technology immediately, with no option to defer until the next year. As results indicate, the command and control policy is extremely costly, totaling $51 million. This cost of is high because, as we have shown, options and flexibility have value and thus reduce cost. In the case of a mandated installation of the technology, there is not opportunity for the utility to limit the downside risk associated with installation. The difference between the dynamic alternative (Tree4 base year value) and the Command and Control Alternative of $35 million is the cost of the loss of flexibly associated with the government mandated installation (Figure 5.2). Though command and control policies are often initiated to protect environmental goods, there are numerous cases in environmental economics proving that the use of market approaches is more efficient in protection of environmental goods using new technologies (the US SO2 trading program is a excellent example).

Major Inputs	Value	Model Outputs	Value
Capital cost of cooling system in base year	$39M	Present Value Command and Control Alternative (Case 1)	$52.9M
Yearly Cost Change	-1%	Present Value of Static Alternative (Case 2)	$22.3M
Volatiltiy associated with derating evetns	40%	Present Value of Dynamic Alternative (Case 3)	$15.7M
Annual increase in electricity prices	5%	**Option Value**	**$6.6 M**

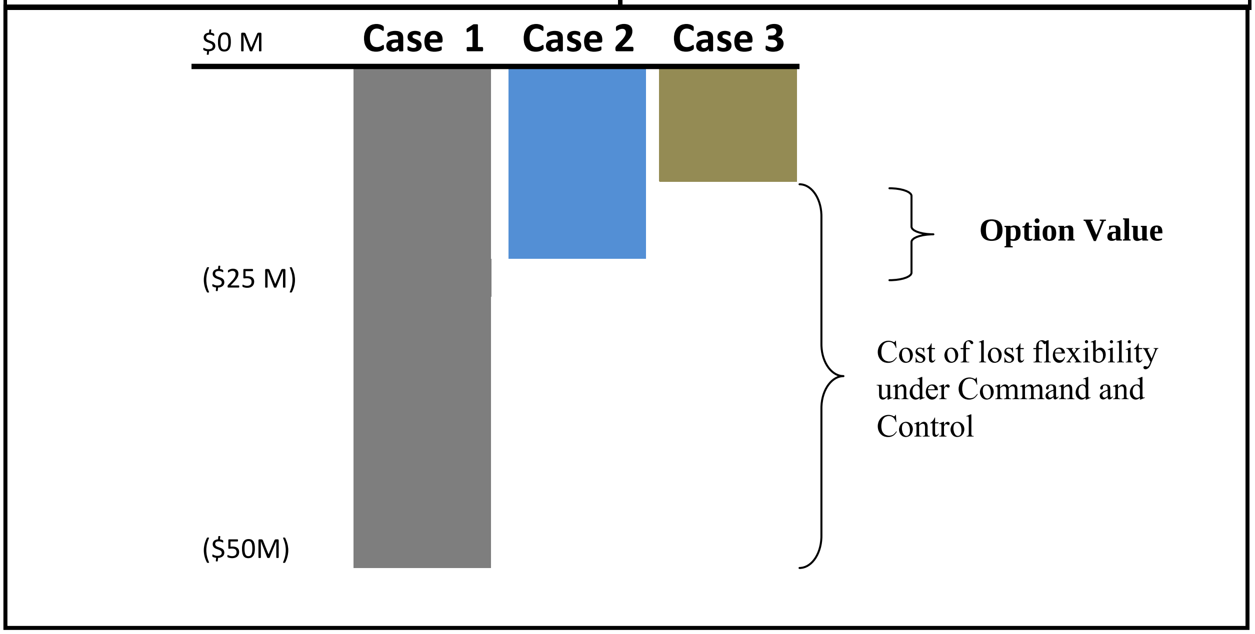


Figure 5.2: Summary of Key Model Inputs and Outputs

5.2 Discussion

This analysis demonstrates that using the NPV approach in the valuation of a technology investment where there are high levels of uncertainty leads to the project being undervalued. The model shows that the real options approach and the methodology used to calculate the dynamic alternative case seems to be a preferable method of analysis when compared to the static NPV method. If this is true, we must then ask how a typical CEO would interpret this approach and its results, as it differs from the "business as usual" approach. From a computational perspective, this analysis is not as straight forward as a standard NPV approach. The U of M Team acknowledges that no firm wants a method of valuation where the finance is so complex that the model looks like a "black box." However, we believe that the additional computational complexity is warranted given the improved valuation. Additionally, while the computation may be more complex, the idea and theory of ROA is very intuitive. In fact, many managers tend to think in a real options framework already. If a Duke analyst showed the results and methodology to a member of upper management who had no knowledge of "option value," but had a working knowledge of basic finance and the manager was walked through the model, the manager should be capable enough to interpret the model as "a technique that captures the value associated with assumption that the manager is rational and will maximize utility" [37]. Thus, if the static alternative is $22 million, and the dynamic alternative calculated is $16 million, then a rational manger provides $6 million in value through his/her ability to make rational decisions and adapt the investment direction of the firm. This is exactly the interpretation that we would want an upper level manager to have.

The analyst with a more extensive knowledge of option valuation would note that the dynamic alternative captures the fact that a manager has the "option" to install or not to install in each period, and the value of this option is the captured difference between the static and dynamic valuations in the model. The Allen Steam Station model and framework is a case where the project competes against itself over time and the manger evaluates it dynamically over time. So, the typical CEO is correct that the rational manager valuation is in fact a dynamic valuation. The $6 million is the value of managerial flexibility – a reflection that the manager that has an option.

"A key advantage of ROA is that it is a gradual improvement, inherently incorporating DCF analysis", Copland and Antikarov (2001)

Additionally, a review of results would help both the CEO and analyst to recognize that an NPV approach is not appropriate to evaluate investment opportunities in environments of high uncertainty, or if NPV is used, it should be noted that the project is likely being undervalued. This is important knowledge for the business community; it raises the question of whether Duke, or any firm dealing with uncertainly, is properly valuing projects.

However, it is not enough to assert that there is a difference between static and dynamic approaches and this is called the option value. Why is the option value important, and how can it be used? As mentioned in the Allen Steam Station Case, with a dynamic valuation $15.7 million and an option value of $6 million, the potential Duke hybrid investment has additional value that was previously unaccounted for. Does this warrant additional spending to develop the hybrid project given its value has increased? This strategic investment question cannot be answered by this model because the Allen Steam Station Case was not modeled as a complex option. However, what Duke is ultimately interested in is a much more complex model, with an additional layer of computational power, which could help answer this question using the ROA framework. In the real world, it is not a simple case of "invest vs. wait." With an additional layer of optionality (i.e. "invest vs. wait" vs. "invest vs. wait and spend R&D and learn"), the ROA model could serve as an internal strategic tool because of the ability to emphasize incremental opportunities arising from investment [38]. Specifically, R&D in a real options framework can be thought of as an incremental investment that can open up new opportunities or keep open a firm's options [60]. Investing $3 million into R&D of the hybrid system may speed up the development time for installation and maintain the option to install the $40 million system. However, ROA, unlike NPV, accounts for the fact that there is no obligation to spend the $40 million. Or in some cases, investment in R&D may be shown to greatly change the value of the option. For example, it can may lower cost of the technology and its installation, or improve efficiency of a hybrid cooling technology. Consequently, the model could help form a Duke manager's thoughts about levels of R&D warranted.   In the model, potential R&D investment would be evaluated against the option value it maintains over time and would not need to be justified against the overall lifetime cost of the project [56]. This feature of the model would allow a very compelling and detailed strategic analysis for R&D.

The Year to Install

One of the capabilities of an ROA analysis is the model's ability to help in identifying the optimal timing of an investment. This can be very useful information in strategic planning. In our model, Tree 4 and Tree 2 can be compared in order to identify the instance where it the utility should install the technology. While this caparison sounds simplistic, it is computationally complex because of the multiple inputs into Tree 4 and the backward iterative node population of Tree 4. Thus, we did not model this capability into our case analysis due to time constraints but it will be considered in future model development.

Engineering Detail

There is one additional minor shortcoming of the model. The costs associated with install vs. wait strategies are not concrete. They are estimates that that were provided by the research team; in some cases we were unable to find concrete numbers, so inputs became "estimates." However, the model was built to be highly flexible, thus allowing inputs to be easily changed or added without affecting the "inner workings" of the model. As a next step in model revision, the real options modelers and engineers should work side by side in developing a more robust model from an engineering perspective.

Managerial Thinking and ROA

Critics of the adoption of ROA will undoubtedly cite a wide range of reasons why ROA should not be used, including its complexity or lack of complexity in handling real world scenarios. Whether ROA is functionally useful for project evaluation is at the discretion of the management of any given firm. In our opinion, we have demonstrated that it is ultimately a useful tool. However, regardless of whether or not one believes ROA is functionally useful; there is no denying that the approach is theoretically useful. One of the greatest benefits of ROA thinking is just that – thinking. The very exercise of working through options systematically begins to change the way management thinks.

Above all else, ROA is distinguished from alternative methodologies in the ways it deals with uncertainty. As demonstrated throughout this Practicum, uncertainly (volatility) is the key driver of value in a ROA approach to valuation, and is what fundamentally makes it different from an NPV analysis The greater the volatility, the wider the range future values for the investment opportunity, and greater the potential value of the project. ROA recognizes the ability to be flexible in investment and limit downside risk while maintaining the upside reward. From the NPV perspective, higher volatility is recognized through higher discount rates, which decrease the value of the investment, thus creating an aversion to uncertainty. It is in this light that McKinsey Consulting has cited that the greatest strategic benefit of a Real Options analysis, is the approach's ability to change the investment culture in a firm [37]. ROA can help shift management's thinking from "fear uncertainty and minimize investment" to "seek gain from uncertainty and maximize learning" [37]. For a firm interested in increasing funding for R&D or investment in a highly volatile market space, this is an invaluable and welcome mind set in most organizations.

"It took decades for DCF analysis to replace payback period analysis, the same will happen for real option analysis",
Copeland (2001)

Wide Application of ROA in the Utility Sector

There are numerous applications for ROA in the energy sector. Duke may want to consider other areas in which ROA may prove beneficial as a strategic tool and help to inform decision makers. For example, the potential for climate change legislation and the adoption of a cap-and-trade system is a scenario that lends itself to ROA. Under a cap-in-trade, a power plant would face the choice of adopting carbon reduction strategies to meet plant's carbon cap or purchase credits to offset its carbon emissions. In an ROA, the credit price would be treated as the underlying asset and the cost of the carbon reduction strategy would like the exercise price. Just as in the case of water technology adoption, the cap-in-trade model could be constructed with enough complexity to serve as a strategic tool to the utility. Furthermore, the dynamic, static, and command and control alternatives could be used to demonstrate to regulators that the most cost effective solution is the approach that provides the most flexibility to those making capital investments.

5.3 Next Steps for U of M Team and Duke Energy

This project has been submitted as part of National Science Foundation grant proposal co-sponsored by Gautam Kaul and Peter Adriaens. The grant application can be found in Appendix D. If the grant is received, the goal is to incorporate more complexity into the model, as well as the incorporation of environmental forecasting ability through the integration of the model with watershed/climate modeling software (Appendix X). The grant would require several students to continue to push forward the ROA effort in the area of water conservation technologies and power production.

Regardless whether or not the grant is received, Duke may want to consider further interaction with the Ross School of Business and the School of Environmental Engineering to continue to the develop the model. As the model stands, it is useful on a level that it highlights that ROA offers significant advantages over typical NPV approaches under conditions of uncertainty. In doing so, it also shows that where expectation of future values (cash flows or costs) are certain, there is no volatility, traditional NPV approaches will continue to be sufficient. But if Duke wishes to utilize the ROA as a strategic investment tool, further model complexity and detail will be necessary. With additional complexity Duke will not only be able to properly value investment under uncertainty, but will also be able to identify optimal timing of the investment in water conservation technology, identify and validate research and design budgets, and understand the capital outlay that the utility would willing to pay for the deferral and or learning options.

The world is becoming increasingly complex and a tool that can assist in decision making in a complex world is extremely valuable. Real options have broad application through the energy sector, as well as most other sectors [37]. The approach will change the way a firm values opportunities; change the way management thinks; and change the way the enterprise creates value.

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Appendices A-E

Appendix A

In order to determine which available technologies would best fit the current power industries investment needs, four main criteria were chosen to aide in the process. These criteria are valued by the industry from both an environmental and financial viewpoint and should therefore be used to determine the best fit technologies.

Water Savings. For the arid regions of the Western United States water availability is scarce and competition for water include domestic, commercial and other industrial uses. In the Southern region, where the climate is typically humid and warm, the water quality and temperature restrict unlimited use of natural waters. Environmental regulations under the Endangered Species Act (ESA), the Clean Water Act (CWA), and many others prevent degradation of the navigable waters of the United States and set many restrictions and permitting requirements for the intake and discharge of water back into the waterway. The less water used, consumptive or withdrawal, results in fewer dilemmas' dealing with water availability and quality as well as any respective costs incurred by using less water.

Effect on Heat Rate. In the power industry, one benchmark as to how efficient an electric generator uses heat is by measuring the heat rate. In the United States, the heat rate is measured as the heat input from the fuel in BTU's per hour for each kilowatt-hour of electricity produced. It is therefore important to keep the heat rate low such that less fuel is needed to produce electricity. The effect on the heat rate is important when determining cooling technologies due to the increase or decrease in efficiency of the fuel which has a direct impact on fuel and operation costs.

Stage of Cooling Technology. Commercial viability of the technology is crucial to investment options. While some technologies are heavily researched and readily available, others are still in the research and pilot stages with the results of cost and water savings still left for determination. If choosing a system with limited availability for replacement components, lack of a reliable customer care program or one without enough up and running examples, then uncertainty for the cost structure significantly increases. It is desirable to have a cooling technology that is both more efficient than current traditional technologies.

Capital Cost. As with any business, the amount of capital needed is key to whether or not the business may be built. High capital costs require larger loans and higher risk of the investment. While all costs cannot be deferred, reducing the amount of capital needed is a plus.

Technology Options

Some of the desired water saving technologies have already been generally reviewed by the power industry. All of these technologies are in different research stages, and require various capital costs. A brief overview of each of these technologies is below:

Coal Drying with Waste Heat and Flue Gas. The main process for this technology is based on the issue of drying the coal feed used in the boilers. The waste heat generated by the circulating hot cooling water (which is leaving the condenser) can be used to help dry the wet-based coal, reducing the need for outside air mechanisms. The heat from flue gas from the boiler may also be used and can result in providing even higher drying temperatures. Some of the potential benefits of this technology include reduced fuel and ash disposal costs, water savings, and reduced station service power. While this technology has proven to be useful, it is still in the research stages and is not popular for traditional water savings. This technology is not capital intensive, but also does not provide large scale water savings, touting lower than 10%.

Evaporation Capture from Cooling Towers. Losses due to evaporation are the largest water loss from recirculating towers but can also provide significant water and cost savings if captured. For cooling towers, the loss due to evaporation is represented by the difference between the blow-down discharge and the replacement fresh water. Capturing the evaporation can be accomplished via cross-currents of ambient airc, producing condensation. Increased condensation and less evaporation can reduce the amount of scaling and fouling produced in the tower as well as operation and maintenance costs to bring in fresh water. It can be expensive in capital due to the having enough area and cross-currents to encourage condensation and water savings range from 12-30%, with the higher range for warmer climates.

Wet Surface Air Condenser for Auxiliary Towers. The operation of WSAC's is generally used for Aux loops, as well as in turbine exhaust vacuum steam condensing and inlet air refrigerant condensing. The WSAC's operates similar to a shell and tube exchanger, but instead of a one-way flow parallel to the tubes, the water flows perpendicular to the tubes and the shell portion is incomplete. While the water flows over the tubes, air is also induced downward over the tubes. Heat from the process (working) fluid will transfer to the water flowing downwards, and then from the water to the air stream via evaporation. The air is then guided to turn 180° as it flows so to have maximum free water removal. Air is then discharged vertically so to prevent recirculation in the WSAC. Some of the main benefits of using the WSAC are reductions in water requirements and discharge, reduced energy requirements and makeup water may be of poorer water quality. This technology is currently being implemented in plants and while still being refined, is not limited to the research stage. It requires approximately less than 72% less area and 60% lower installation cost than that of an air cooled heat exchanger. Capital costs, however, may be more expensive. Water savings primarily come from makeup water and blowdown water, totaling a reduction of 5%; however other minuscule costs may come from treatment and disposals. For large reductions in water, this technology does not compete, but is still useful for other benefits.

None of the above listed technologies proved to have significant water savings as well as reasonable increases in the capital costs. The heating rates were within ±3% in general, and the additional benefits were not necessarily the goal of the proposed water saving technology. The remaining technology, the Heller hybrid, can range in water savings between 2-90% and therefore may be more of a viable option when compared to the increase in capital costs. The Heller hybrid is thus described in its own section with accompanying detailed information for the four technology parameters.

Heller Hybrid Systems

<u>Company Overview:</u> The Heller system was developed by the EGI Contracting Engineering Co, Ltd located in Budapest, Hungary. EGI is owned by GEA Group, founded in Germany. GEA is also located in the United States and does not make the Heller systems but instead make the parallel condensing system (PAC-system). Currently the PAC-system, not the Heller, is commercially found in the United States. The Heller system is however available for purchase to US power industry clientele.

<u>Background of Heller:</u> The Heller System ® is a combination system that uses primarily indirect air cooling via a dry cooling tower. According to the manufacturer, the system is "environment friendly, saves water equivalent to the consumption of a town of 50,000 inhabitants for each 100 MW facilitating the licensing of power projects."1 By indirect cooling, the waste heat from the power plant is exchanged in a condenser to a closed circuit cooling water loop2. The warmed water is then cooled by the ambient air via natural draft cooling in heat exchangers.

In order to take advantage of the wet cooling system's higher efficiency over dry cooling, the Heller can be retrofitted or manufactured with a water spraying system. This water system allows additional cooling by distributing water over the fins of the heat exchanger. By spraying the water instead of the traditional once-through wet cooling system which requires massive amounts of available water, water-efficiency is captured. The Heller hybrid system incorporates this additional water spraying system. There were several hybrids of the Heller system developed by EGI to improve water conservation relative to wet cooling, reduce investment costs relative to dry cooling, and improve both environmental and summertime turbine outputs. The types of Heller hybrids2 are as follows:

- Dry System with Water Spraying: Add water to air heat exchanger in the dry cooling tower. Good for peak-shaving during summer days and is a low additional investment option to original system.
- HEAD Cooling System: The cooling tower is replaced with HEAD Coolers, which use a Deluge water distributor to spray water over hot tubes leaving a continuous water film on both sides of the fins. Ideal for summer peaking or seasonally varying heat loads. Also contains two variations:
    - Dry Tower with delugable Peak Coolers
    - Dry/deluged Cooling System
- (Series) HELLER & Evaporative ((S)H&E) Cooling System: Can be used to convert existing wet cooling towers to dry/wet ones by either series or parallel connections.

Due to limited public information regarding all the above variations for the Heller hybrid, the following analysis used data only for the Dry System with Water Spraying unless otherwise noted.

Water Savings: Savings range and the conservation of water for the hybrid systems are made relative to consumption of an all-wet cooling system. The range for all hybrids is 2% - 90% annual water usage (excluding consumption) relative to that of an all wet cooling system2 as shown in the table below.

Heller Hybrid Type	**Water Usage (relative to all wet cooling system)[2]**
Dry System with Water Spraying	2-10%
HEAD Cooling System: Dry Tower with delugable Peak Coolers	5-10%
HEAD Cooling System: Dry/deluged Cooling System	10-35%
HELLER & Evaporative Cooling System	20-70%

The Heller hybrid Dry System with Water Spraying can be categorized by what temperature minimum is needed for the water spraying to occur. These variations are as follows:

1) Heller (Var. 1) is for a traditional Heller (all dry cooling).
2) Heller (Var. 2) is for spraying applied when the temperature is above 32.2°C.
3) Heller (Var. 3) is for spraying applied when the temperature is above 28°C.
4) Heller (Var. 4) is for spraying applied when the temperature is above 25°C.

Using the Heller (Var.4) would provide the worst-case scenario since it has the lowest temperature requirement before water spraying is utilized.

Efficiency losses: Using the Heller hybrid (Var. 4) model versus the Traditional Evaporative Wet cooling towers, the following electricity generations and consumptions were found by EGI:

	Heller (Var. 4)	Evaporative (Wet)	Efficiency loss by Heller (%)
Electricity Generation (GWh/yr)	5534.6	5617.4	1.47
Net Electricity (GWh/yr)	5498.4	5568.2	1.25
Average Net Output (Mwe)	738.53	747.92	1.26

Heller efficiency losses in terms of electricity generation are below 2%.

Capital Costs: The most water intensive Heller variation (Var. 4) does have a higher investment cost comparable to the Evaporative Cooling system. This takes into account the credits for substitution of chimneys with stack-in-towers, eliminating FGD recuperator and surface painting. The Heller (Var. 4) would cost $49.79 million per unit installed, whereas the Evaporative Cooling system would cost $36.23 million per unit installed3. These costs do not take investment or operational costs of the water system portions.

Operation and Maintenance Costs: The auxiliary power consumption for the Heller (Var. 4) system is decreased by approximately 26%. This decrease was found by the thermal calculation of the Heller (Var. 4) requiring 36.24 GWh/yr and the Evaporative cooling requiring 49.14 GWh/yr.

The other main source of O&M costs is from water consumption. The Evaporative system requires water for the following process steps3,

- Sourcing & environmental fees
- Collecting and pipe raw water to site
- Water treatment and cooling water conditioning
- Disposal of sludge and blow-down

The specific water cost is estimated to be $0.35/m3 and the water source is about 25 miles away from the cooling tower3. The Heller (Var. 4) water quality must be higher and therefore the estimated specific cost is $0.50/m3.

	Heller (Var. 4)	Evaporative
Investment cost of water infrastructure ($M)	2.5	14
Make-up water cost ($M/yr)	0.18	3.27

As shown in the above table the Heller (Var. 4) would require a lower investment and make-up water cost as compared to the Evaporative cooling system.

Conclusion

While all of the water saving technologies provide some type of savings in terms of water usage and costs due to water savings, the capital costs relative to the maximum amount of water saved is best represented by the Heller hybrid system. It should also be noted that while no Heller hybrids are currently operating in the United States, the Heller's are globally operating in many countries including Armenia, Syria, Turkey, and Hungary.

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Appendix B: First 10 years and scenarios of example NPV analysis

Allen		
1000 g/drought	5,103,000	
Price/1000 g	$1.16	
Price/drought	$ 5,938,380	
Drought Every	5	years
Discount Rate	7.5%	
Scenarios	1,000	
Avg NPV	$11,880,658	
Stdev NPV	$5,725,972	
Minimum NPV	$0	
Maximum NPV	$31,390,182	

Blue=inputs

Year Scenario	1 Drought	2 Drought	3 Drought	4 Drought	5 Drought	6 Drought	7 Drought	8 Drought	9 Drought	10 Drought
1	Yes	Yes	Yes	No	No	No	No	No	No	No
2	No	No	No	No	No	Yes	No	No	No	Yes
3	No	No	No	No	No	No	No	No	No	Yes
4	No	Yes	No	No	No	No	Yes	No	No	No
5	No	Yes	Yes	No	No	Yes	No	No	No	No
6	No	Yes	No	Yes	No	Yes	No	No	Yes	No
7	No	No	No	No	No	No	No	No	No	No
8	No	No	No	Yes	No	No	No	No	No	No
9	No	No	No	Yes	No	No	Yes	No	No	No
10	No	No	No	Yes	No	No	No	Yes	Yes	No

Year Scenario	1 $ Lost	2 $ Lost	3 $ Lost	4 $ Lost	5 $ Lost	6 $ Lost	7 $ Lost	8 $ Lost	9 $ Lost	10 $ Lost	PV (SUM)
1	$5,938,380	$5,938,380	$5,938,380	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,309,859
2	$ -	$ -	$ -	$ -	$ -	$5,938,380	$ -	$ -	$ -	$5,938,380	$ 8,596,057
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$5,938,380	$ 5,374,519
4	$ -	$5,938,380	$ -	$ -	$ -	$ -	$5,938,380	$ -	$ -	$ -	$ 15,105,505
5	$ -	$5,938,380	$5,938,380	$ -	$ -	$5,938,380	$ -	$ -	$ -	$ -	$ 13,766,677
6	$ -	$5,938,380	$ -	$5,938,380	$ -	$5,938,380	$ -	$ -	$5,938,380	$ -	$ 20,554,981
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	$ -	$ -	$ -	$5,938,380	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,446,662
9	$ -	$ -	$ -	$5,938,380	$ -	$ -	$5,938,380	$ -	$ -	$ -	$ 12,663,540
10	$ -	$ -	$ -	$5,938,380	$ -	$ -	$ -	$5,938,380	$5,938,380	$ -	$ 15,290,630

Appendix C – Tree Construction

This appendix contains two separate sets of descriptions on the construction of a binomial ROA model. Approach 1, the incremental approach, was followed by the team in the construction of the ROA excel based model. In this approach, the option value is calculated “incrementally.” This is done by comparing the lowest cost static alternative versus the cost of a dynamic alternative.

The team initially evaluated the option value associated with the Heller Hybrid using Approach 2. Approach 2 attempted to calculate the option value in isolation rather than incrementally. However, after the construction of the model under this approach, we concluded that this approach in fact, did not capture the option value associated with the project. Though, intuitively, the approach is sound, and the when volatility increased, the “option value” decreased. This violates one of the key attributes of option valuation.

Approach 1: The Incremental Approach

Step 1. Calculate the costs of the no-technology and the technology today strategies. Clearly, this is how things will are done in the real world, but it is wrong. This analysis of course depends critically, among other things, on the starting cost of derating events

Step 2. Clearly, the decision to install the technology is not now or never. This is an example of a project competing with itself over time. If the management waits, it bears the current year’s cost of compliance by doing nothing, but they learn more about the cost of future derate events. For example, if the cost shoots up, installing a the technology becomes attractive! This is the option value. If costs fall of course they continue to wait. Recognize that the assumption here is that installing a technology is an irreversible commitment (or excessively expensive thing to reverse), but doing nothing is NOT. If Duke could uninstall the hybrid system it would, but it would make the analysis considerably more complex.

An important operational issue: in figuring out the technology valuation, keep the cash flows from sale of allowances less any variable costs SEPARATE from the installation costs (net of PV of depreciation tax shield of course). This is because it is consistent with the notion of an option: the value of an option comes from the sale of allowances (less any variable costs), while the installation cost (net of PV of depreciation tax benefit) is like the strike price.

The Step by Step:

(a) Build the Cost tree…based on u and d, which is based on volatility and risk free rate. Call this “Cost Tree”.

(b) Now build a tree for the do nothing (base case) scenario BUT with a difference. Populate this tree with the CURRENT year’s costs (given the derate cost at each point). Call this Tree 1. This tree is important because it shows the cost of waiting an additional year to make a commitment to install the technology. This is what will trigger early exercise of our American Option.

(c) Build a tree for the hybrid alternative, again only with the CURRENT year's costs at each node. Call this Tree2.

(d) Now create another tree based on Tree2, which shows the cumulative remaining cost of compliance under the hybrid strategy at each point. Call this Tree3. Mechanics: Go to last year…the numbers in the last year will be exactly the same as in Tree2. In the last but one year it will be that year's cost PLUS the expected PV of the last year's costs, using the risk-neutral probabilities and the risk-free rate. Work backwards and populate the whole Tree3. The reason for doing this is that this tree tells us the BENEFIT of an immediate commitment to the scrubber; which is the UNDERLYING ASSET of the hybrid strategy! Note that this does not include the installation cost (net of PV of depreciation tax shield) because that is the strike price (or cost of getting the benefit).

(e) Now we figure out the cost of the dynamic strategy, by choosing the best thing to do at each point. Again, go to the last year, and ask the following question: If we have not switched to the scrubber by this last year, would we do so then? For each point in the last year, choose the maximum of the estimate in Tree1 (do nothing) and the corresponding number in Tree3 that shows the remaining cost of scrubber LESS net cost of getting scrubber (investment – PV of deprecation tax shield). Call this Tree4. Work backwards now…In last but one year, compare two things: (i) the cumulative costs of scrubber in Tree3 less the net cost of installing scrubber at that point; versus (ii) Cumulative costs of continuing from this point by making no modification, but instead waiting to make the best decision next year. This value = current year's cost of compliance with no modifications (Tree2) PLUS the expected PV of the best decision in the next year using the risk neutral probabilities and the risk-free rate. Keep doing this backwards and you should arrive at today…this should be the # you want…the cost of the dynamic strategy.

(f) The option to wait and make the best decision later (given the starting allowance price and volatility) will now be the DIFFERENCE between the BEST STATIC strategy and the one in (e).

Approach 2: The Original Traditional Binomial Approach (Incorrect)

There are many ways to do an ROA. Our original approach in the construction of the model was to use a more traditional binomial approach that is often used in finance text books that teach ROA. However, the case where a project competes with itself over time we found some confusion associated with this methodology. We found it easier to understand and, and more importantly convey, the concept better if done in an incremental fashion. Gautam Kaul believes that, if feasible, it is always good to do it the incremental way. Below is a descriotion of our original methodology. This approach was abandoned and not used, but included in order to be

There are a number for different approaches that can be can be used is real option analysis. Each has its merits. However, this analysis uses a binomial option valuation model. In short, this approach evaluates real options by creating a binominal lattice (tree), for a given number of time steps within the investment horizon. At each node in the lattice, the value of the underling asset may either increase or decrease (move "up" or "down"). Once all nodes have been evaluated in this manner, this approach searches for the optimal investment strategy at each final node, and then in an iterative process works backwards through the tree to the first node where the calculated result is the value of the option.

Option valuation using this method is, as described above, is a multi step process:

1. Generation of cost Tree, NPV trees, and Action Tree
2. Calculation of option value at each final node using the Action tree
3. Progressive calculation of option value at each earlier node; the value at the first node is the value of the option.

Tree Generation for De-rating Events

In our example, the underlying variable is the total cost of de-rating events. Under our assumptions, the value of the investment is driven the hybrid technology's ability to minimize this costs. Costs are a function of two variables 1) the replacement cost and the market cost of water and 2) the frequency and severity of de-rating events.

In order to generate a cost tree, we establish an upward or downward movement. At each node or step in the investment horizon, it is assumed that the cost of de-rating will move up or down by a specific factor (u or d) per step of the tree. The up and down factors are calculated using the underlying volatility, σ and the time duration of a step, t, measured in years, days, hours, etc.

The volatility of the underlying variable, cost of de-rating events, is a cumulative volatility of based on a standard deviation in replacement and market costs and duration and frequency of de-rating events. However, by focusing our analysis on the over all cost, we avoid modeling the volatility for both variables which may become extremely complex. Instead, we only must calculate a single volatility via standard deviation of the costs of historical de-rating events provided to us by the utility.

We evaluate volatility on daily basis. However, the step movements of the tree (nodes) represent monthly movements throughout the year. We are most interested in May – October. It is in these months, the majority of de-rating events occur. Nevertheless, because we need attach the appropriate volatility with the tree step movements, we must add up the entire month's volatility in order to use a cumulative volatility value to be used in the model.

With the tree established, the model constructs a two parallel NPV trees for the wet cooling option and the hybrid option. This accomplished by taking each node value valuated in the cost tree running it through a NPV model for each option. The result is two expected costs at every node, the NPV cost of doing nothing and the NPV cost of installing the hybrid system.

$$u = e^{\sigma\sqrt{t}}$$

$$d = e^{-\sigma\sqrt{t}} = \frac{1}{u}.$$

As an aside, it is important to notice form the equations above that d = 1/u, thus the tree is recombinant. This property ensures that if the cost of water moves up and then down (u,d), the cost will be the same as if it had moved down and then up (d,u) — it is here that the two paths merge or recombine. This property reduces the number of tree nodes, makes modeling more user-friendly and less complex, and thus accelerates the computation of the option price.

Finally, we construct a fourth tree – an Action Tree. At each node, using the associated NPV cost values from the two NPV cost trees discussed above, we take the NPV cost of doing nothing less the NPV cost of installing the hybrid technology. If this value is positive, the rational manger would install the scrubber and this calculated value is placed into the Action Tree in the appropriate node. If this value is negative, the once through cooling system would remain, and a value of "zero" would be placed into the Action Tree. This process is replicated at node until the Action Tree is complete.

Calculation of option value at the final node for a Hybrid Cooling Tower

Using the Action Tree, we construct year another tree – the option tree. At each of the final nodes of the Option Tree -- i.e. the last node in which an investment decision on a hybrid cooling system can be made -- the option value in that period is the value in the Action tree because the option to invest no longer exists after the final year.

Progressive calculation of option value for a Hybrid Cooling Tower

At each interior node you have two options, invest or wait. The rational manager will pursue the higher value option. In order to populate the Option Tree, we look at the value in the Action Tree appropriate period and compare this value to the present value of waiting to next period to invest. There are two possible outcomes from waiting:

- the high case, based on the up-movement, and
- the low case, based on the down-movement.

The value of waiting is a weighted average of these two cases discounted back to the decision making period using the risk free rate. We are able to use the risk free rate because the probability of the up and downward movements are risk natural probabilities. The risk neutral probability is a function of the risk free rate and the relationship in the up-down movements, but is not imperative to fully understand its calculation here. The bottom line is that at each node, the rational manager will evaluate the value to pick the higher of these values.

This process is repeated for each interior node until the current period (Time period 0) is reached. The final result is a monetary representation of the value of the option to install the hybrid cooling system over the investment horizon.

Appendix D – Example of Portions of the Model Trees and NPV Spreadsheets

"Cost Tree"

Yealry Derate Cost For Allen Steam Station											
Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Node	0	1	2	3	4	5	6	7	8	9	10
0	($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)	($4,055,200)	($5,754,603)	($8,166,170)	($8,000,000)	($8,000,000)	($8,000,000)	($8,000,000)
1		($704,688)	($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)	($4,055,200)	($5,754,603)	($8,166,170)	($8,000,000)	($8,000,000)
2			($496,585)	($704,688)	($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)	($4,055,200)	($5,754,603)	($8,166,170)
3				($349,938)	($496,585)	($704,688)	($1,000,000)	($1,419,068)	($2,013,753)	($2,857,651)	($4,055,200)
4					($246,597)	($349,938)	($496,585)	($704,688)	($1,000,000)	($1,419,068)	($2,013,753)
5						($173,774)	($246,597)	($349,938)	($496,585)	($704,688)	($1,000,000)
6							($122,456)	($173,774)	($246,597)	($349,938)	($496,585)
7								($86,294)	($122,456)	($173,774)	($246,597)
8									($60,810)	($86,294)	($122,456)
9										($42,852)	($60,810)
10											($30,197)

Tree1

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Node	0	1	2	3	4	5	6	7	8	9	10
0	($623,000.00)	($884,079.08)	($1,254,567.94)	($1,780,316.65)	($2,526,389.58)	($3,585,117.47)	($5,087,523.85)	($4,984,000.00)	($4,984,000.00)	($4,984,000.00)	($4,984,000.00)
1		($439,020.68)	($623,000.00)	($884,079.08)	($1,254,567.94)	($1,780,316.65)	($2,526,389.58)	($3,585,117.47)	($5,087,523.85)	($4,984,000.00)	($4,984,000.00)
2			($309,372.64)	($439,020.68)	($623,000.00)	($884,079.08)	($1,254,567.94)	($1,780,316.65)	($2,526,389.58)	($3,585,117.47)	($5,087,523.85)
3				($218,011.22)	($309,372.64)	($439,020.68)	($623,000.00)	($884,079.08)	($1,254,567.94)	($1,780,316.65)	($2,526,389.58)
4					($153,629.91)	($218,011.22)	($309,372.64)	($439,020.68)	($623,000.00)	($884,079.08)	($1,254,567.94)
5						($108,261.16)	($153,629.91)	($218,011.22)	($309,372.64)	($439,020.68)	($623,000.00)
6							($76,290.36)	($108,261.16)	($153,629.91)	($218,011.22)	($309,372.64)
7								($53,760.91)	($76,290.36)	($108,261.16)	($153,629.91)
8									($37,884.67)	($53,760.91)	($76,290.36)
9										($26,696.88)	($37,884.67)
10											($18,812.97)

Tree2

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Node	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	($317,254.24)	($316,061.56)	($314,925.67)	($313,843.87)	($312,813.58)	($311,832.35)	($310,897.85)	($4,984,000.00)	($4,984,000.00)	($4,984,000.00)	($4,984,000.00)
1		($316,061.56)	($314,925.67)	($313,843.87)	($312,813.58)	($311,832.35)	($310,897.85)	($7,589,693.74)	($4,984,000.00)	($4,984,000.00)	($4,984,000.00)
2			($314,925.67)	($313,843.87)	($312,813.58)	($311,832.35)	($310,897.85)	($2,792,092.29)	($4,603,381.95)	($7,589,693.74)	($4,984,000.00)
3				($313,843.87)	($312,813.58)	($311,832.35)	($310,897.85)	($1,027,153.35)	($1,693,489.58)	($2,792,092.29)	($4,603,381.95)
4					($312,813.58)	($311,832.35)	($310,897.85)	($377,868.60)	($623,000.00)	($1,027,153.35)	($1,693,489.58)
5						($311,832.35)	($310,897.85)	($139,010.09)	($229,188.89)	($377,868.60)	($623,000.00)
6							($310,897.85)	($51,138.96)	($84,313.88)	($139,010.09)	($229,188.89)
7								($18,812.97)	($31,017.34)	($51,138.96)	($84,313.88)
8									($11,410.64)	($18,812.97)	($31,017.34)
9										($6,920.91)	($11,410.64)
10											($4,197.74)

Tree3

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Node	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	$ (4,298,982.10)	$ (4,265,354.21)	$ (4,230,044.92)	$ (4,192,970.17)	$ (4,154,041.67)	$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
1		$ (4,265,354.21)	$ (4,230,044.92)	$ (4,192,970.17)	$ (4,154,041.67)	$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
2			$ (4,230,044.92)	$ (4,192,970.17)	$ (4,154,041.67)	$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
3				$ (4,192,970.17)	$ (4,154,041.67)	$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
4					$ (4,154,041.67)	$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
5						$ (4,113,166.76)	$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
6							$ (4,070,248.09)	$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
7								$ (4,025,183.50)	$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
8									$ (3,977,865.67)	$ (3,928,181.96)	$ (3,876,014.06)
9										$ (3,928,181.96)	$ (3,876,014.06)
10											$ (3,876,014.06)

Tree4

								Dynamic Strategy			
Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Node	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
0	$ (15,188,578.56)	$ (19,081,631.14)	$ (23,403,512.50)	$ (27,744,925.60)	$ (31,245,085.49)	$ (32,280,048.94)	$ (33,082,136.74)	$ (33,907,428.81)	$ (34,756,578.34)	$ (35,630,256.01)	$ (36,529,150.33)
1		$ (11,749,890.10)	$ (15,087,871.25)	$ (19,056,769.81)	$ (23,536,917.11)	$ (28,166,018.51)	$ (32,143,153.62)	$ (33,907,428.81)	$ (34,756,578.34)	$ (35,630,256.01)	$ (36,529,150.33)
2			$ (8,871,665.31)	$ (11,568,472.14)	$ (14,912,524.91)	$ (18,933,914.77)	$ (23,552,490.17)	$ (28,468,634.78)	$ (32,974,425.11)	$ (35,630,256.01)	$ (36,529,150.33)
3				$ (6,578,283.85)	$ (8,667,008.62)	$ (11,327,042.87)	$ (14,648,261.80)	$ (18,682,427.82)	$ (23,389,766.68)	$ (28,546,188.84)	$ (33,588,220.92)
4					$ (4,817,571.28)	$ (6,388,225.78)	$ (8,423,577.53)	$ (11,025,250.13)	$ (14,289,385.47)	$ (18,279,144.00)	$ (22,973,100.88)
5						$ (3,502,027.39)	$ (4,659,056.65)	$ (6,175,840.13)	$ (8,145,986.09)	$ (10,673,190.30)	$ (13,859,591.79)
6							$ (2,538,372.67)	$ (3,378,574.96)	$ (4,487,124.67)	$ (5,941,058.05)	$ (7,832,583.69)
7								$ (1,842,865.63)	$ (2,448,331.39)	$ (3,248,807.77)	$ (4,303,179.79)
8									$ (1,345,462.80)	$ (1,781,278.91)	$ (2,356,695.56)
9										$ (990,917.48)	$ (1,306,030.56)
10											$ (737,730.67)

"Static_Install" Spreadsheet

Cumulative Total Annual Present Value Cost
($52,942,335)

Year	Discount Factor	Capital Cost	Total Depreciation	Tax Effect of Deprc	Salvage Value	Efficiency loss (%)	Total reduced Generation	Loss Proft from Reduced Power	Increased O&M (frm BAU) with Hybrid System)	Tax Savinigs from Loss	Total Annual Cost	Total Annual Present Value Cost
2009	1.00	($39,000,000)	$1,950,000	($735,150)	$0	1%	70,000	($350,000)	($30,000)	$143,260	($39,971,890)	($39,971,890)
2010	0.93	$0	$1,950,000	($735,150)	$0	1%	70,000	($367,500)	($31,500)	$150,423	($983,727)	($919,371)
2011	0.87	$0	$1,950,000	($735,150)	$0	1%	70,000	($385,875)	($33,075)	$157,944	($996,156)	($870,081)
2012	0.82	$0	$1,950,000	($735,150)	$0	1%	70,000	($405,169)	($34,729)	$165,841	($1,009,206)	($823,813)
2013	0.76	$0	$1,950,000	($735,150)	$0	1%	70,000	($425,427)	($36,465)	$174,133	($1,022,909)	($780,372)
2014	0.71	$0	$1,950,000	($735,150)	$0	1%	70,000	($446,699)	($38,288)	$182,840	($1,037,297)	($739,578)
2015	0.67	$0	$1,950,000	($735,150)	$0	1%	70,000	($469,033)	($40,203)	$191,982	($1,052,404)	($701,261)
2016	0.62	$0	$1,950,000	($735,150)	$0	1%	70,000	($492,485)	($42,213)	$201,581	($1,068,267)	($665,263)
2017	0.58	$0	$1,950,000	($735,150)	$0	1%	70,000	($517,109)	($44,324)	$211,660	($1,084,923)	($631,435)
2018	0.54	$0	$1,950,000	($735,150)	$0	1%	70,000	($542,965)	($46,540)	$222,243	($1,102,411)	($599,639)
2019	0.51	$0	$1,950,000	($735,150)	$0	1%	70,000	($570,113)	($48,867)	$233,355	($1,120,775)	($569,745)
2020	0.48	$0	$1,950,000	($735,150)	$0	1%	70,000	($598,619)	($51,310)	$245,023	($1,140,056)	($541,632)

"Cost_No_install" Spreadsheet

Cumulative Total Annual Present Value Cost
($22,281,869.40)

Node	Year.month (MASTER)	Discount Factor	Total Cost of Derating Events	Tax Savings from Loss	Increase in O&M	Total Annual Cost	Total Annual Present Value Cost
0	2009.0	1.000	($1,000,000.00)	$377,000.00	$ -	($623,000.00)	($623,000.00)
1	2010.0	0.935	($1,080,000.00)	$407,160.00	$ -	($672,840.00)	($628,822.43)
2	2011.0	0.873	($1,166,400.00)	$439,732.80	$ -	($726,667.20)	($634,699.28)
3	2012.0	0.816	($1,259,712.00)	$474,911.42	$ -	($784,800.58)	($640,631.04)
4	2013.0	0.763	($1,360,488.96)	$512,904.34	$ -	($847,584.62)	($646,618.25)
5	2014.0	0.713	($1,469,328.08)	$553,936.68	$ -	($915,391.39)	($652,661.41)
6	2015.0	0.666	($1,586,874.32)	$598,251.62	$ -	($988,622.70)	($658,761.05)
7	2016.0	0.623	($1,713,824.27)	$646,111.75	$ -	($1,067,712.52)	($664,917.70)
8	2017.0	0.582	($1,850,930.21)	$697,800.69	$ -	($1,153,129.52)	($671,131.88)
9	2018.0	0.544	($1,999,004.63)	$753,624.74	$ -	($1,245,379.88)	($677,404.14)
10	2019.0	0.508	($2,158,925.00)	$813,914.72	$ -	($1,345,010.27)	($683,735.02)

"Option 1" Spreadsheet

Cumulative Total Annual Present Value Cost
($623,000.00)

Option 1						
Node	Year.month (MASTER)	Total Cost of Derating Events	Tax Savings from Loss	Increase in O&M	Total Annual Cost	Total Annual Present Value Cost
0	2009.0	($1,000,000.00)	$377,000.00	$ -	($623,000.00)	($623,000.00)
1	2010.0	($1,080,000.00)	$407,160.00	$ -	($672,840.00)	$0.00
2	2011.0	($1,166,400.00)	$439,732.80	$ -	($726,667.20)	$0.00
3	2012.0	($1,259,712.00)	$474,911.42	$ -	($784,800.58)	$0.00
4	2013.0	($1,360,488.96)	$512,904.34	$ -	($847,584.62)	$0.00
5	2014.0	($1,469,328.08)	$553,936.68	$ -	($915,391.39)	$0.00
6	2015.0	($1,586,874.32)	$598,251.62	$ -	($988,622.70)	$0.00
7	2016.0	($1,713,824.27)	$646,111.75	$ -	($1,067,712.52)	$0.00
8	2017.0	($1,850,930.21)	$697,800.69	$ -	($1,153,129.52)	$0.00
9	2018.0	($1,999,004.63)	$753,624.74	$ -	($1,245,379.88)	$0.00
10	2019.0	($2,158,925.00)	$813,914.72	$ -	($1,345,010.27)	$0.00

“Option 2” Spreadsheet

Cumulative Total Annual Present Value Cost
($317,254)

Option 2

Node	Year.month	Efficiency loss (%)	Total reduced Generation	Loss Proft from Reduced Power	Increased O&M (frm BAU) with Hybrid System)	Tax Savinigs from Loss	Total Annual Cost	Total Annual Present Value Cost
0	2009.0	1%	70,000	($350,000)	($30,000)	$143,260	($236,740)	$0
1	2010.0	1%	70,000	($367,500)	($31,500)	$150,423	($248,577)	$0
2	2011.0	1%	70,000	($385,875)	($33,075)	$157,944	($261,006)	$0
3	2012.0	1%	70,000	($405,169)	($34,729)	$165,841	($274,056)	$0
4	2013.0	1%	70,000	($425,427)	($36,465)	$174,133	($287,759)	$0
5	2014.0	1%	70,000	($446,699)	($38,288)	$182,840	($302,147)	$0
6	2015.0	1%	70,000	($469,033)	($40,203)	$191,982	($317,254)	($317,254)
7	2016.0	1%	70,000	($492,485)	($42,213)	$201,581	($333,117)	$0
8	2017.0	1%	70,000	($517,109)	($44,324)	$211,660	($349,773)	$0
9	2018.0	1%	70,000	($542,965)	($46,540)	$222,243	($367,261)	$0
10	2019.0	1%	70,000	($570,113)	($48,867)	$233,355	($385,625)	$0

Appendix E: NSF Grant Proposal

1. Project Motivation: Investment Decisionmaking for Alternative Cooling Technologies

The National Energy Technology Laboratory (NETL) projects that the majority of new power generating capacity installed between 2005 and 2030 will be in arid regions, including southeast, southwest, and western states [1,2]. Those are the areas where adopting new water-conserving technologies will likely be most cost-effective for plant operators, due to the shrinking availability and the rising cost of water. Figure 1 represents a map of the Thermoelectric Cooling Constraint Index, which is based on the Water Supply Sustainability Index (WSSI). The index takes into account the amount of available renewable water and sustainable groundwater use, limits on freshwater withdrawals needed to protect endangered species, an area's susceptibility to drought, and its expected growth in water use and power production. An area is considered highly constrained if its WSSI is 3 or greater and moderately constrained if its WSSI is between 2 and 3 [3].

QuickTime™ and a
decompressor
are needed to see this picture.

Fig. 1. Projected thermoelectric cooling constraint indices in 2025 [3]

Water constraints and other water risks such as elevated water temperature and biofouling result in an increased frequency of de-rating events (reduction in power production capacity) due to condenser back-pressure buildup, obstruction of cooling circulating water flow through condenser tubes, or insufficient steam generation [4]. For example, high condenser back-pressure is the most obvious plant measure that results in lost revenue or excess operating costs, because it is directly related to the power output from the turbines and thus reduced efficiency. Revenue and profit loss from each 0.1" HgA rise in back pressure in a 525 MW generating unit results in an increase of 0.17% in heat rate, correlating to a loss of approx. 1 MW of power and nearly $250,000/year lost revenue. The total cost of derating events at a 7 mWh plant in 2007 in North Carolina ranged from $ 8-32 per mWh; this cost increased to $18-36 per mWh in 2008. Aggregated over the production capacities of power utilities, the economic impact of back pressure and other water-related derating events is substantial.

Despite the strong linkage of energy production to water availability and other risks (e.g. temperature, scaling), energy and water policymaking and investment in technologies that conserve water are hampered by a predisposition to view water as an inexhaustible resource, with limited price elasticity, because the cost of water does not drive the operational expenses of a power plant [5,6]. The cost of pre- and post-treating water can range from as low as 22 cents/kgal (where treatment requirements are minimal) to as much as $4.28/kgal (if produced water from oil and gas exploration is used) [7]. We posit that the cost of water-related derating events on power output should be considered to assess the value of technology investments, rather than the actual cost of water. In this project, watershed modeling tools and financial analyses will be integrated in a decision support system to quantify the impact of water-based derating events on the investment options for utilities in alternative water cooling technologies.

2. Background

2.1. Power Production and Water Conservation Technologies

To meet escalating demand, a new 500 MW power plant must be built in the U.S. *each week* for the next 15 years [1,2]. Even in the midwestern and northeastern U.S., where population growth is relatively flat, demand for electricity is anticipated will rise due to increases in per capita consumption. The makeup of future power production is uncertain, but expected to be largely driven by coal, natural gas and nuclear (Figure 2). For thermoelectric capacity additions using conventional cooling tower systems, a corresponding 21-48% increase in freshwater consumption will occur in 25 years. Over the next 25 years, freshwater consumption for thermoelectric generation is projected to rise 74% in the Rocky Mountain states, 199% in Florida, and a staggering 352% in California [1]. Even in the southeastern U.S., where freshwater is not ordinarily viewed as a limiting resource, an extended drought in 2007 led to imposition of water use restrictions normally associated with water conservation in western states.

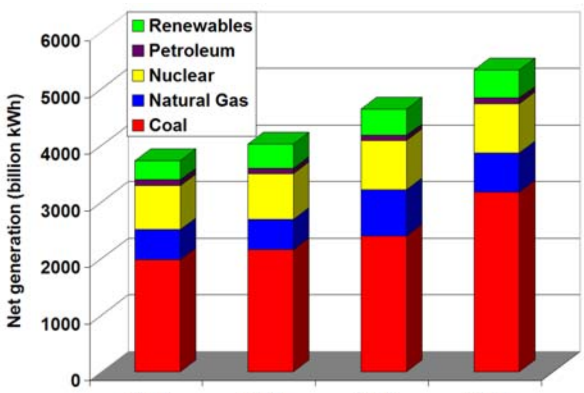


Figure 2: Projected electric power generation

Predictably, shortfalls in available freshwater disrupt local economies and engender disputes between energy and agricultural interests over water appropriations. Surprisingly, this occurs even in traditionally water-rich northern states such as Minnesota and Illinois, where permits for new ethanol plants have been rejected over concerns about excessive water use and mining of groundwater resources [5]. Similar renegotiated permits are on the rise in Georgia, North Carolina, Arizona and California for coal-fired and nuclear power plants.

Climate change may potentially reallocate freshwater resources and affect water temperature over the next several decades. Although regional-scale information on changes in water resources is uncertain, it is generally held that climate change will increase the intensity of droughts, floods and peak summer temperatures. Given that the capital costs for the construction of new thermoelectric plants are typically written off over a 40-year life cycle, it is prudent to consider whether the water resources presumed to be accessible at a plant location will in fact be available over the full service lifetime of the generating facility. Indicators of changes in water allocation and pricing contracts were presented at the 2009 Electric Utilities Environmental Conference, impacting utilities in the southwest and southeast.

To address the water demands of once-through systems, retrofits with helper towers or the use of groundwater and treated wastewater is considered to dilute discharge and mitigate temperature problems. As a result of Clean Water Act Section 316(b) provisions and public pressures, most jurisdictions now discourage or prohibit construction of new once-through cooling systems. Because recirculating systems cool by evaporation from towers or cooling ponds, they consume more water than once-through systems, but they withdraw a lot less. The actual rates of water withdrawal and consumption depend on the plant's generation technology and environmental conditions. The changing mix of once-through and recirculating cooling systems—as well as water-conserving improvements to them—enabled the electric power industry to reduce its water withdrawals per unit of power generated by a factor of three over a 50-year period: from 63,000 gal/MWh in 1950 to 21,000 gal/MWh in 2000 [7]. Over the same period, power generation increased by a factor of 15. The investment cost in water efficiency technology is substantial, relative to closed loop tower retrofit costs (Table 1).

Table 1. Emerging Water Conservation Technologies

Technology	Water Savings	Effect on Heat Rate	Research Stage, Issues	Capital Cost*
Coal Drying w/ Waste Heat and Flue Gas	10%	-3%	Bench Pilot, technical effectiveness	0.5x
Evaporation Capture from Cooling Towers	20%	Depends	Utility Pilot, size and cost	3x
Wet Surface Air Condenser for Aux Towers	Make-up water and blowdown disposal	minimal	Cost, changing condenser, pilot underway	1.5x
Heller Hybrid	80-90%	+1.5%	Cost reduction, minimize parasitic load	4x

**Capital & installed cost: closed-loop cooling tower retrofit cost, ~$40m*

The development and adoption of alternative cooling technologies increases the options for plant developers and decision-makers, enabling them to reduce water-related costs and plant profitability. It has been argued that water-conservation technologies, alone or in combination, could raise annual margins by 1 to 3 % [8]. This does not include the potential gains from addressing the derating events, which is the metric utilities use to assess profitability.

The challenge of water use has pressured the nation's utilities to make investment decisions that capture environmental and corporate objectives with respect to water use and electricity production.

2.2. Water-Based Derating Events and Cooling Technology Investments

Utilities, especially those using once through cooling, are faced with the question of when or if to invest in technologies that reduce water use in an uncertain operational environment. The uncertainties associated with power generation are: (1) The frequency and severity of de-rating events, and (2) The cost of de-rating events. Many methods and algorithms have been proposed to capture the impact of reduced power production in electric power systems [9-11]. Under the assumptions of this analysis, the cost of a de-rating event at a plant is a function of two types of costs - a replacement cost and a market cost [12]. To understand these two types of costs let us use a simplified example:

> Due to elevated water temperatures, Plant A experiences a de-rating event which results in a curtailment of 100,000 MWh over the duration of the event. As a result of the 100,000 MWh reduction in production, the utility must increase the production at Plant

B. However, because the utility is a profit-maximizing firm, we can assume that the cost per MWh at Plant B (Cb) is higher than the cost of production per MWh at Plant A (Ca). If this were not true, production of the 100,000 MWh would never have occurred at Plant A. Given Plant B power production is more costly, the utility will only increase Plant B production by 80,000 MWh in order to meet system demand and deliver on negotiated contracts. Thus, there is a net system production decrease of 20,000 MWh. If the de-rating event had not occurred and 100,000 MWh had been produced at Plant A, 80,000 MWh would have been delivered to the system users and the extra 20,000 MWh would have been sold into a regional interconnect system, like the PJM Interconnection, at market price (Mp).

In this example, there are two costs realized by the utility. The first cost is a *replacement cost* because the cost of producing a Plant B is greater than the cost of production at Plant A. The second cost is an opportunity cost or *market cost* - the lost revenue associated with selling excess system power in to the regional interconnect. At the most basic level, the total cost of the de-rating event can be expressed as:

$$\text{Total Cost} = \text{Replacement Cost} + \text{Market Cost}$$
$$\text{Total Cost } (\$) = [80{,}000 \text{ MWh } (Cb - Ca)] + [200{,}000 \text{ MWh } (Mp)]$$

It is important to note, however, that a de-rating event at one plant results in a reduction in MWh generation. Therefore, the variable cost per MWh at Plant A (VC_A) will increase and the cost per MWh at Plant B (VC_B) will decrease (fixed costs can be ignored due to amortization at both plants). Thus, a more appropriate Total Cost equation may be:

$$\text{Total Cost } (\$) = [\$80{,}000 \text{ MWh } (VC_B - VC_A)] + [\$20{,}000 \text{ MWh } (Mp - VC_A)]$$

The challenge faced by utility mangers is two-fold. The frequency and severity of de-rating events in the future are unknown; costs associated with each event are uncertain. Intuitively, it would seem plausible that investment in a hybrid system would prove beneficial because it would allow mangers to react to changing water conditions as they shift into cooling operations. However, due to the expense of this technology investment, traditional Discounted Cash Flow (DCF) valuation approaches may demonstrate the project to have a negative NPV. It is thus important to understand the limitations of the DCF technique. The NPV is based on a set of fixed assumptions related to the project payoff (a deterministic approach), where in reality the payoff is uncertain and probabilistic. DCF does not take into account the contingent decisions available and managerial flexibility to act on those decisions. Additionally, DCF does not take into account that a rational managerial will limit downside risk. In general, a full reliance on the DCF approach may lead to the rejection of promising projects because of uncertainty.

Real options analysis (ROA) offers a way to address these limitations of DCF, because it captures the value of options embedded in projects. By making options explicit and quantifying their value, management is better able to make rational decisions based on more complete information.

2.3. Real Options Analysis: Valuing Technology Investment Options

The term “real options” is commonly used in the context of strategic corporate planning when faced with uncertain future cash flows [13] - though the notion of real options can easily be broadened to capture various types of decision-making under uncertainty. The basic concept is that wherever there is an option, there is a chance to benefit from the upside, while avoiding downside risk at the same time. The uncertainties associated with water risks, allocation policies, and electricity pricing present a challenge for investment decisions of energy utilities [e.g. 14-16]. As stated before, these uncertainties and their effect on investment decisions in the power sector in technologies are taken into account as probability weights in computing an expected value of discounted cash flow (DCF). However, this methodology does not quantitatively take into account investment risks and the value for utilities and stakeholder decision makers of keeping investment options open.

Real options analysis (ROA) enables a nuanced quantitative approach to modeling the impact of uncertainty, and to account for the flexibility of strategic investment [13]. ROA is particularly useful for the derating analysis in this study, because: (i) individual elements of risk can be modeled separately and in combination to look at their relative contribution to overall risk; (ii) it provides for an evaluation of the risk of water-based derating events in financial terms so they can be related to technology investments and (iii) the approach is very flexible and allows for scenario testing in terms of the impact of future water risk uncertainties on technology investment options [17-19]. Real options approaches have been applied to model the effects of uncertain climate change policy, for example, on how to deal with emissions trading and CO_2 penalties [20-23], adoption of various electricity generation technologies [24], research and development expenditures for renewables [25], technology adoption decisions under uncertainty [14,17], investment decisions for SO_2-emissions control technology [26], and for alternative cooling technologies [27].

Why adopt this approach to quantify the risk of investment in alternative cooling technologies? Getting the right type of investment in cooling infrastructure is a requirement to cope with and adapt to exposure risks (uncertainties) from water (allocation policies, temperature, climate change) for sustained energy production. In previous applications of ROA, the risk premium associated with policy uncertainty for coal- and gas-fired power plants to invest in carbon capture and storage (CCS) technologies was evaluated, and shown to require an increase in the carbon price by 16-37%, relative to the situation of policy certainty [22]. Generally, utilities require sufficiently high output price levels (e.g. elasticity of energy pricing), or cost of a derating event in terms of power output, to be induced to invest in environmental control technologies. The rationale is that they optimally would not want to commit to an irreversible investment that could turn out to be unprofitable in the event of a (water) price and/or (allocation) policy change [18].

In this project, the focus is on the decisions faced by a utility when evaluating an investment in water saving technologies [7, 27]. Specifically, the analysis will initially focus on the utility’s option to install a hybrid cooling system in a plant currently using a once through cooling system – a waiting option. A hybrid system is an interesting technology to consider because the flexible nature of the technology results in an embedded switching option.

Waiting option: When any key factor in the business environment is uncertain (e.g. exposure to water risk), the utility may be able to acquire higher returns (or minimize costs) by waiting for a certain period of time before making an investment rather than acting immediately and installing the technology, e.g. a hybrid cooling system. It is this option that the model evaluates, based on uncertainty faced by the utility in terms of the total cost of de-rating events over a given period as a function of the replacement cost, market cost, and duration/severity of de-rating events.

Switching Option: This option refers to the flexibility built into the hybrid technology itself. By incorporating flexibility to react to the uncertainty in the future of water temperature or availability (the ability to the wet or dry cooling), the hybrid technology allows a manger to adapt to future conditions. However, the model does not explicitly "value" this option because we assume that if the technology is installed, the manager will act rationally and operate the drying cooling option when it has a lower cost than the wet cooling option. Thus, the value of this option is wrapped into the evaluation of the waiting option.

Learning Option: This analysis may move on to evaluation of Research and Design (R&D) or phased technology implementation. This type of technology investment is called a "Learning option." If the technology implementation can be developed in a phased manner, the utility can test the suitability of the technology by developing the initial phase with low costs. Based on this result, the firm can modify (or abandon) the following phase of development in order to maximize the total project value. Intuitively the concept is well understood by managers, but it is not incorporated into a traditional discounted cash flow (DCF) approach.

When compared with DCF analysis, a more commonly used valuation approach, the real options approach requires a more sophisticated understanding of the underlying financial theory [e.g. 13, 28]. Conceptually, it is not difficult once the theory is understood. However, a lack of available examples where ROA is used, compounded with the continuing focus on DCF and NPV analysis, and a sense of complexity of the real options approach among mangers are just a few of the reasons that have prevented this approach from becoming the mainstream method of valuing real assets. This analysis hopes to demonstrate that the ROA approach has significant value when evaluating investment decisions and is flexible enough to systematically incorporate any type of uncertainty, such as climate variability, into a manager's decisions framework.

3. Project Objectives

This project will develop and apply a decision support system (DSS) that incorporates environmental uncertainties in a real options financial framework to make time-dependent investment decisions in alternative cooling technologies. The objectives will initially be informed by watershed and power production data from a testbed in the southeast. The ultimate decision tool will have broad applications regardless of geographical constraints, or mode of power production (coal, natural gas, and nuclear).

a. The *first objective* is to construct the real options framework from the perspective of data input and output objectives (e.g. specification of options, analysis of water-based derating events, determining volatility of events such as electricity and water pricing, and technology cost).

b. The *second objective* will be a coupling of the output of watershed-based models (e.g Watershed Analysis Risk Management Framework, WARMF) to the derating events described in objective 1. The temporal variability over decade-scale timeframes will be incorporated in the ROA framework to analyze how this volatility impacts downstream financial decision-making.

c. The *third objective* focuses on scenario testing using the integrated watershed and financial tools to assess the robustness of the decision support system for cooling technology alternatives applied to coal-fired and nuclear power plants under future climate scenarios.

4. Research Plan: Background and Technical Approach

The methodology for incorporating water-based events into technology investment using ROA will follow steps that integrate environmental and financial modeling approaches (Figure 3):

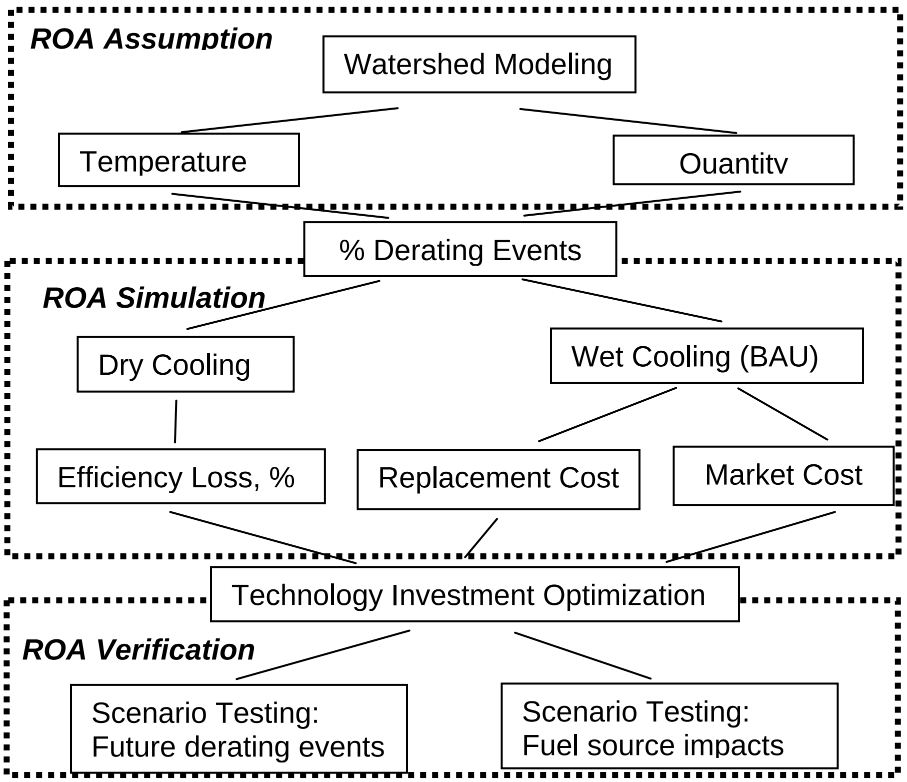


Figure 3. Flowchart of research objectives and outcomes

- <u>ROA Assumption</u>: The financial model incorporates the 'volatility' of power output (expressed as cost of a derating event), resulting from the availability and temperature of water. This historical trend will be modeled using the WARMF model, and future trends will be modeled stochastically under various climate scenarios.

- <u>ROA Model</u>: The model will answer whether and when it is worth investing in dry (or hybrid) cooling technology, given the water-based derating cost volatility, relative to business as usual (BAU) wet cooling. Each of these options have different 'penalties', whereby BAU incurs market and replacement costs, and dry/hybrid exhibit a higher investment (and efficiency) cost. The outcome is a timing of exercising the hybrid/dry investment option relative to BAU.

- ROA Verification: This step will conduct scenario testing of the impact of variable costs associated with derating events on investment decision-making, and assess how these events can be explained by WARMF predictions. The argument here is that whereas the cost of volatility of derating events on power output is known, the predictability of the water-related source of this volatility is not. This will be applied to variable fuel sources.

A description of the state of art and technical approach is provided in the sections that follow.

4.1. Real Options Analysis and Water Technology Investments (Adriaens, Kaul)

Background: There are a number of different numerical approaches that can be can be used to solve complex option related problems [e.g. 29]. Whereas each has its merit, this analysis will employ a multiplicative binomial option valuation model [e.g. 30], which showed that options can be valued by discounting their terminal expected value in a world of risk neutrality. In short, this approach evaluates real options by creating a binominal lattice (tree), for a given number of time steps within the investment horizon. At each node in the lattice, the value of the underling asset may either increase or decrease (move “up” or “down”). Once all nodes have been evaluated in this manner, this approach searches for the optimal investment strategy at each final node, and then in an iterative process works backwards through the tree to the first node where the calculated result is the value of the option. This process is illustrated for a hypothetical example in Figure 4.

The binominal option valuation model visually demonstrates the movement of the value of the project, as well as the real option values, and this characteristic makes it easier for the user to intuitively understand the real options. Additionally, this approach can deal with more complicated real options. The model is also mathematically simpler when compared to alternatives such as the Black-Scholes model (a mathematical model of the market for an equity, in which the equity's price is a stochastic process; 31), and is therefore relatively easy to build and implement using spreadsheet tools. Furthermore, the binominal option valuation model is based on the risk-neutral argument, on which the Black-Scholes equation is also based. Due to this, the model does not require risk-adjusted discount rates, the need for which sometimes causes problems in valuing real options. The user needs only to discount by the risk free rate and not the estimated risk adjusted discount rates.

Technical Approach: Option valuation using this method is, as described above, is a multi step process: 1. Generation of a cost Tree, NPV trees, and an Action Tree; 2. Calculation of the option value at each final node using the Action tree; and 3. Progressive calculation of the option value at each earlier node; the value at the first node is the value of the option. The basic ROA approach will address the following questions:

(1). What is the optimal timing of the investment in water conservation technology, and what would we be willing to pay for the deferral option?
(2). How do electricity pricing uncertainties and water-based uncertainties influence the timing and choice of strategic investment?

1. Tree Generation for De-rating Events

In our example, the underlying variable is the total cost of de-rating events. Under our assumptions, the value of the investment is driven the hybrid technology's ability to minimize this costs. Costs are a function of two variables 1) the replacement cost and the market cost of water and 2) the frequency and severity of de-rating events.

In order to generate a cost tree, we establish an upward or downward movement. At each node or step in the investment horizon, it is assumed that the cost of de-rating will move up or down by a specific factor (u or d) per step of the tree. The up and down factors are calculated using the underlying volatility, σ and the time duration of a step, t, measured in years, days, hours, etc. An example for a single node binomial tree is provided in Figure 4 (q is the risk free probability of an 'up' move, 'C' is the value of the call option in either an 'up' or a 'down' move).

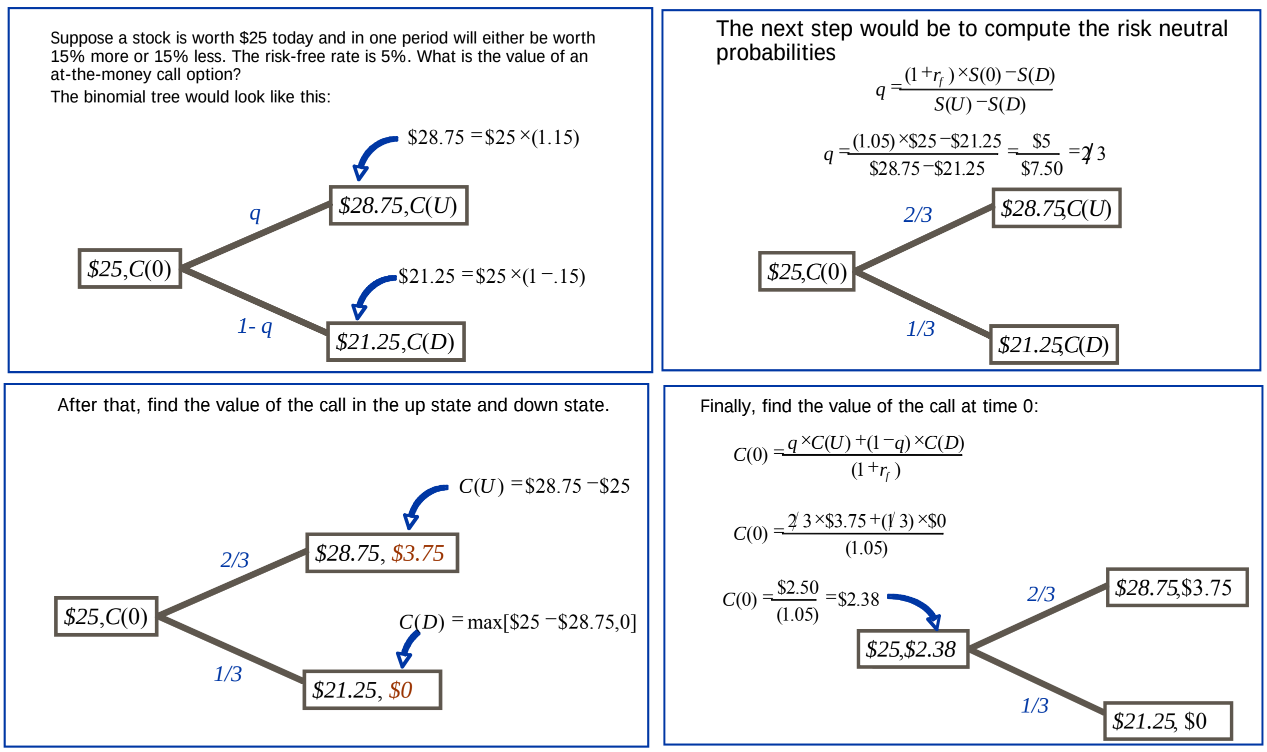
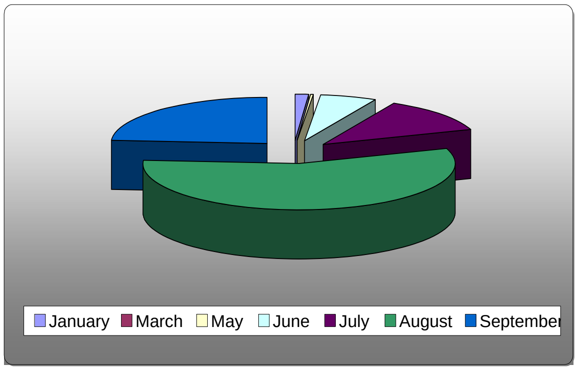


Figure 4. Theoretical approach to ROA using a single node binomial tree (from 32)

The volatility of the underlying variable, the cost of de-rating events, is represented through the cumulative volatility of a standard deviation of market and replacement costs, and duration and frequency of de-rating events. By focusing our analysis on the overall cost, we avoid modeling the volatility for both variables individually, which may become extremely complex. Instead, we will calculate a single volatility by using the standard deviation of the costs of historical de-rating events provided to us by the utilities (past trends, objectives 1 and 2), and will probabilistically model future trends in de-rating events using various climate scenarios (objective 3).

The volatility of de-rating events will be evaluated on a daily basis (data are available and will be aggregated in hourly time steps). However, the step movements of the tree (nodes) will represent monthly movements throughout the year, because we are most interested in the May to October timeframe (Figure 5, left). In the southeast, it is in these months that the majority of de-rating events occur, in part because of drought and temperature events (other events



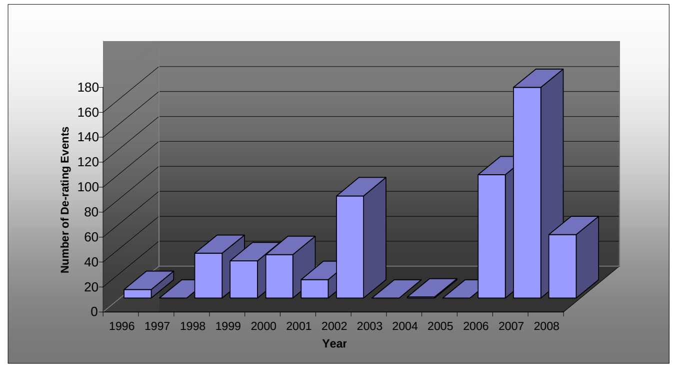


Figure 5: Distribution of derating events in 2007 and trends since 1996 (data from Duke Energy)

includebiofouling and scaling). Nevertheless, because we need attach the appropriate volatility with the tree step movements, we must add up the entire month's volatility in order to use a cumulative volatility value to be used in the model. Monthly nodes will be constructed for the 1996-2008 timeframe for which data are available from utilities (Figure 5, right).

The data will be projected forward 20, 40 or 60 years to capture the remaining active use of power plants. With the tree established, the model constructs two parallel NPV trees; one for the wet cooling option and one for the hybrid option. The parallel trees are developed by taking each node value that is valuated in the cost tree, and calculate it using an NPV model for each option. The result is two expected costs at every node, the NPV cost of doing nothing and the NPV cost of installing the hybrid system.

$$u = e^{\sigma\sqrt{t}}$$
$$d = e^{-\sigma\sqrt{t}} = \frac{1}{u}.$$

positive, the hybrid technology is favored and this calculated value is placed It is important to notice from the equations ($\sigma\sqrt{t}$ is the cumulative variance) above that d = 1/u, thus the tree is recombinant. This property ensures that if the cost of water moves up and then down (u,d), the cost will be the same as if it had moved down and then up (d,u) — it is here that the two paths merge or recombine. This property reduces the number of tree nodes, makes modeling more user-friendly, and thus accelerates the computation of the option price.

Finally, we construct a fourth tree – an Action Tree. At each node, using the associated NPV cost values from the two NPV cost trees discussed above, we take the NPV cost of doing nothing less the NPV cost of installing the hybrid technology. If this value is into the Action Tree in the appropriate node. If this value is negative, the once through cooling system would remain the technology of choice, and a value of "zero" would be placed into the Action Tree. This process is replicated at each node until the Action Tree is complete.

Calculation of option value at the final node for a Hybrid Cooling Tower
Using the Action Tree, we construct the option tree. At each of the final nodes of the Option Tree -- i.e. the last node in which an investment decision on a hybrid cooling system can be made -- the option value in that period is the value in the Action tree because the option to invest no longer exists after the final year.

Progressive calculation of option value for a Hybrid Cooling Tower
At each interior node there are two options, invest or wait. The rational manager will pursue the higher value option. In order to populate the Option Tree, we look at the value in the Action Tree appropriate period and compare this value to the present value of waiting to next period to invest. There are two possible outcomes from waiting:

- the high case, based on the up-movement, and
- the low case, based on the down-movement.

The value of waiting is a weighted average of these two cases discounted back to the decision-making period using the risk free rate. We are able to use the risk free rate because the probability of the up and downward movements are risk neutral probabilities. The risk neutral probability is a function of the risk free rate and the relationship in the up-down movements, but is not imperative to fully understand its calculation here. The bottom line is that at each node, the rational manager will evaluate the value to pick the higher of these values. This process is repeated for each interior node until the current period (Time period 0) is reached. The final result is a monetary representation of the value of the option to install the hybrid cooling system over the investment horizon.

4.2. Watershed Analysis Risk Management Framework (Lastoskie)

Background: In this project, the WARMF (Watershed Analysis Risk Management Framework) watershed management tool, created by Systech in partnership with the Electric Power Research Institute and available from the U.S. EPA [33,34], will be developed into a decision support system for assessment of the water resource impacts of planned electric power capacity additions. It was initially developed as a decision support system for the entire 12,330 km2 (~5,000 mile2) Catawba River Basin of North and South Carolina, but has since been applied to over twenty watersheds. This dynamic watershed simulation model calculates daily surface runoff, groundwater flow, non-point source loads, hydrology, and water quality

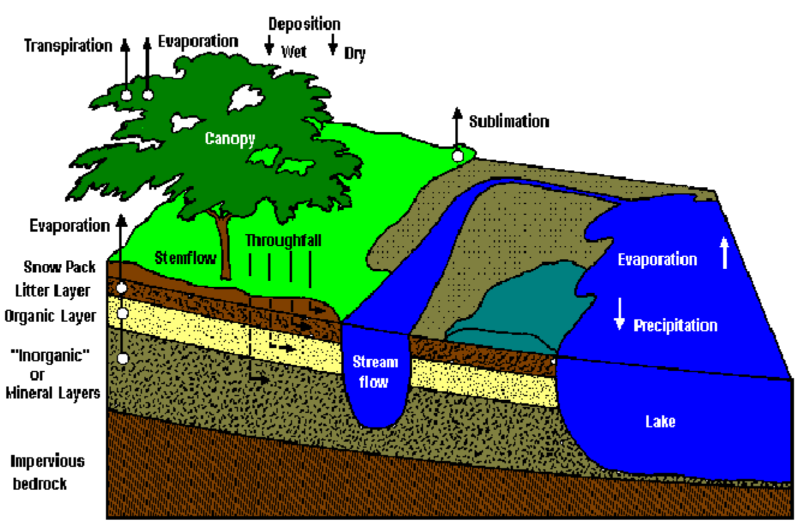


Figure 6: WARMF process model to simulate freshwater flow.

of river segments and stratified reservoirs [35, 36].

A schematic of the WARMF modeling framework is shown in Figure 6. Input topography, land cover, and meteorology data are applied to a network of interconnected catchment basins and surface water segments to simulate snowpack accumulation, snowmelt, groundwater percolation, moisture content of soil layers, groundwater table elevation, and lateral flow to neighboring streams and lakes. Water infiltrates into pervious soils based on soil moisture content, volume of water available for infiltration, and hydraulic conductivity. Under saturated soil conditions, the model simulates surface runoff and soil erosion. Evapotranspiration is calculated based on latitude, air temperature, and relative humidity. Subsurface lateral flow and overland flow entering the river is then routed from one river segment to the next downstream segment until it reaches the watershed outlet. The management of water impacts the available streamflow and reservoir volumes, and is defined in the model by specified reservoir releases, diversions, and irrigation applications. Nonpoint source loads are simulated for each sub-watershed and land use category using a build-up/wash-off algorithm. Heat budgets and mass balances are performed to calculate temperatures and concentrations of water constituents in each soil layer, river segment, and lake compartment. Figure 7 exemplifies a flow and temperature simulation for the St. John's river and Lower Creek in the Catawba watershed.

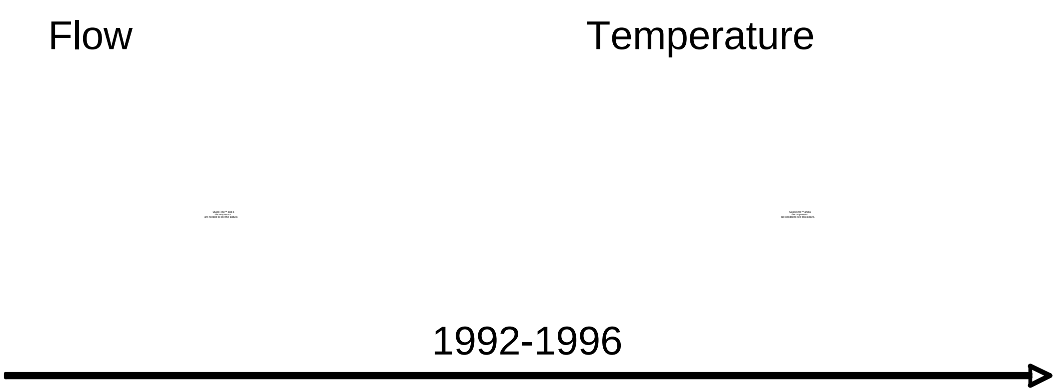


Figure 7. Comparison of WARMF model simulations and observations in the Catawba watershed

Model input coefficients and output visualizations are accessible via a GIS-based watershed map. Model predictions are viewed as a time series output of flows, concentrations, and water shortages/surpluses at various watershed locations. Shortages, available pass-through, and point/nonpoint pollutant loadings, are displayed via color-coded maps and bar graphs.

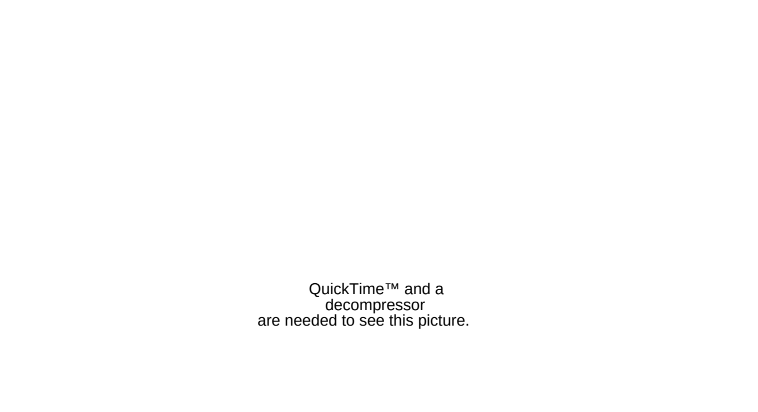


Figure 8

<u>*Technical Approach*</u>: Our initial focus will be on the Upper Catawba watershed (Figure 8), where two of the once-through power plants are located for which we have detailed data (from the utility) on de-rating events and cost (see also Figure 5). The attached letters of support indicate that Duke energy is willing to (and indeed already

has) share(d) operational data with the PIs. These data comprise water intake (in gal/kWh) and temperature data, as well as hourly de-rating events for the Allen and Marshall plant. These de-rating events have to be analyzed for those due to water-related causes (quantity, temperature, fouling, etc..); initial analysis for the 2007-2008 timeframe indicate that 10% of the events are due to water.

The watershed identified for analysis will be delineated into a network of land catchments, river segments and reservoirs using 30 m digital elevation model data and a National Hydrography Dataset stream network. Input data on meteorology, land use, observed stream flows, diversions, and reservoir releases will be obtained from national databases. To capture power generation impacts on the watershed, additional data will be gathered with guidance of utilities on power plant withdrawals and return flow volumes and temperatures. Calibrations will be performed by comparing simulated and observed flows at locations with available gauging data. Landscape parameters (soil thickness, field capacity, hydraulic conductivity) will be adjusted within a reasonable range, based on local knowledge, to improve hydrology predictions for the water budget including global, seasonal and event-specific balances (Table 2). Statistical comparisons will be used to determine quality of fit.

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are needed to see this picture.

Table 2. Data input needs and sources for WARMF

In accordance with the flowchart in Figure 3, the WARMF model outputs for the upper Catawba basin, and specifically the rivers where the Allen and Marshall plant are located (e.g. flow and temperature) have to be translated into water-related de-rating events. This analysis will be conducted by calibrating the monthly simulated data points of WARMF with the monthly averaged water-based de-rating events as analyzed in objective 1. The calibration will be informed by operational metrics that trigger derating events (e.g. temperatures exceeding 95F or 102 F; plant-specific water flows impacting reduction of numbers of turbines in operation, etc…). Statistical correlations will be developed between the time series of WARMF simulations and derating events, to establish how well WARMF explains the extent of derating events. We recognize that, even though WARMF has both the temporal and spatial resolution to inform subwatershed-specific withdrawals, the model may not capture the water-based derating events fully, because of events caused by events other than flow and temperature, and the lower spatial resolution of the model inputs. The correlation thus developed (objective 2) will be used in conjunction with the ROA model configuration (objective 1) to conduct the scenario testing (objective 3).

4.3. Scenario Testing of ROA Model to Identify Cooling Technology Investment Options

Background: The ROA-based investment decisions are informed by the cost of water-related derating events, hence, the sensitivity of the model outcomes to the future uncertainty of these events needs to be assessed. Implicit in this analysis is the need to differentiate between the fuel sources used for power production. Whereas objectives 1 and 2 use once-through cooling of coal-fired plants as the base case for investment analysis, this objective will address the ROA sensitivity across coal, oil, natural gas and nuclear fuel sources, and under variable climate change conditions impacting water quantity and temperature. Table 3 shows the differential use of water in these systems, which will impact the cost of derating events. The letters of support from Duke Energy and Palo Verde Nuclear Station indicate the willingness of these utilities to share data for our work and support the value of the work proposed here. Further, we have an on-going agreement with the Electric Power Research Institute (through LimnoTech) to engage the broader utility industry in energy-water nexus projects.

*Table 3. Average Water Withdrawal and Consumption Factors (*on site water use only; 3)*

Generation Type	Cooling Water System Type	Boiler Type	Type of FGD	Withdrawal Factor (gal/MWh)	Consumption Factor (gal/MWh)
Coal	Once-Through	Subcritical	Wet	27,113	138*
			None	27,046	71*
	Wet Cooling Tower	Subcritical	Wet	531	462
			None	463	394
	Open Cooling Pond	Subcritical	Wet	17,927	804
			None	17,859	737

Generation Type	Cooling Water System Type	Withdrawal Factor (gal/MWh)	Consumption Factor (gal/MWh)
Nuclear	Once-Through	31,497	137*
	Wet Cooling Tower	1,101	624
Oil & NG	Once-Through	22,740	9*
	Wet Cooling Tower	250	16
	Cooling Pond	7,890	11

Changes in precipitation, snow pack and evaporation expected with global warming will alter distribution and annual variability of surface water. Loss of stationarity due to climate change will impact water resource management [37]. Climate change models provide input data to a hydrologic model to project the effects of climate change on regional water availability. The most significant variables to consider are precipitation, temperature, and whether or not storage of water in seasonal snow or ice is important to regional resources. Climate change effects are often counterintuitive. In many regions, more precipitation is expected; however, increased temperatures will amplify evaporation such that there is net drying of soil moisture and surface water. Climate change is expected to increase the frequency and severity of droughts and intense storms, and shift flow cycles that water management systems have been designed to accommodate. Hence, it can be anticipated that the frequency of de-rating events will increase in the future and influence cooling technology investment decisions.

Technical Approach: The incorporation of climate change scenarios in the WARMF model will be accomplished using an iterative stochastic sampling technique developed in the WARMF ZeroNet module [38]. The module uses a range of scenarios based on a database of historical climate data. An ensemble of simulations will be run to produce a probabilistic distribution of results characterizing resulting stream flow shortage, and surplus of water, as well as temperature in watersheds faced with potential drought or competing water uses. This is exemplified in Figure 9, where the tool simulates stream flows under variable climate conditions.

Climate impact assessment will be conducted in two parts. First, the intrinsic climatic sensitivity of the watershed will be established to arbitrary incremental changes in temperature and precipitation. Second, the sensitivity of the watershed to climatic changes will be combined with probability density estimates of temperature and precipitation changes within the time horizon of interest (20-60 years out). The output of these simulations will be used as inputs in the correlation between derating events and temperature/water flows developed in Objective 2. The implicit assumption is that trends in water-driven derating events and trends in water flows/temperature will behave the same in time. The cost of derating events will be treated in the bionomial option valuation as described in Objective 1 to derive at an investment decision. Considering that the climate impact is based on probability estimates, the risk-free probabilities of the up and down moves will be based on the mean values of these estimates. We may consider alternative statistical metrics as well to compute the propagation of asset values and the value of the call at time zero under climate uncertainty.

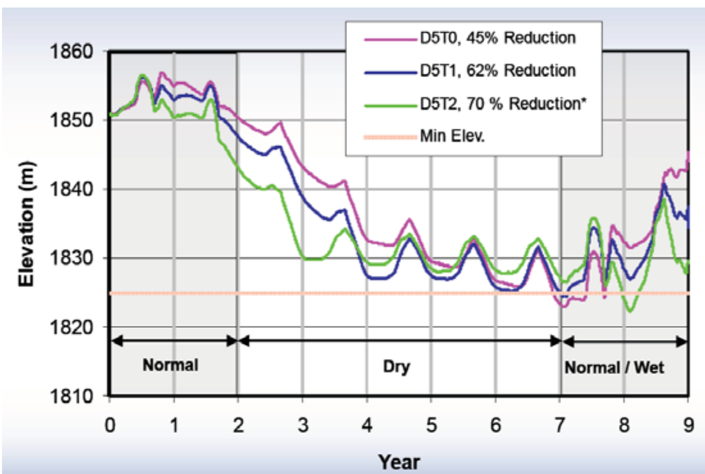

Figure 9: Simulated Navajo Reservoir elevations under a 5-year drought condition. Scenarios represent a range of expected temperature increases and required reduction of reservoir releases to meet a minimum elevation criterion: D5T0 (0º increase, 45% reduction of outflows), D5T1 (1º increase, 62% reduction), D5T2 (2º increase, 70% reduction).

A second area of uncertainty that warrants scenario testing of call option valuation is the source of fuel for power production, and the associated withdrawal and consumptive factors. Consumptive water use for nuclear power production is similar to that of coal power, and is 30-50x higher than for natural gas and oil plants. However, the cost of production is higher for all three fuel sources than it is for coal, which impacts the cost of derating events. We will focus primarily on the nuclear power plants, because they represent the other extreme in power production cost, and are otherwise similar in water use. Two conditions will be considered in ROA analysis of the 'business-as-usual' case: (i) derating events (similar to coal-plants in objective 1), and (ii) water pricing strategies (based on proposed water contract negotiations that would increase the price of water by 10x in the SW). The alternative cooling technology considered is hybrid cooling as in objective 1. Future projections of call option values will be assessed as described earlier for coal plants.

5. <u>Education and Outreach Activities</u>

5.1. <u>Undergraduate Research Assistantships</u>. The project will engage undergraduate research assistants, which will be recruited through two programs (Marian Sarah Parker Scholars and University Research Opportunity Program) to foster participation in research by underrepresented women and minority groups. Prof. Adriaens is an advisor to the UROP program, and has taught in their seminar series about the convergence of technology for sustainability and business fundamentals. Both Profs. Lastoskie and Adriaens have a track record of engaging undergraduate students in their research programs.

5.2. Curriculum Development. New graduate course materials will be developed to utilize research themes and content from the proposed work in the Energy Systems Engineering distance degree program at UM. Lastoskie serves on the executive committee of this program. Lastoskie teaches CEE 567: Energy Infrastructure Systems. Prof. Adriaens teaches entrepreneurship courses (ENGR 520 and ENGR 521) including CleanTech entrepreneurship, which uses the scientific method of hypothesis testing to assess the viability and scalability of technology-based businesses. Aside from entrepreneurial finance, the course teaches strategy, marketing and value creation from technology. Prof. Kaul teaches a Sustainability Finance course, which covers financial options analysis for technology investments, to students in the Erb Institute for Global Sustainable Enterprise.

5.3. Professional Outreach. Graduate students will travel on-site to the case study region to work with collaborators during the summer months of the project to facilitate exchange of information and decision support tools between academia and stakeholders in industry. Prof. Adriaens' affiliation (20% appt.) with LimnoTech complements the team with the developers of the WARMF model and the ZeroNet module (L. Weintraub, formerly at Systech Engineering), and relationships with EPRI (Dr. Goldstein – Technical Executive, Water and Ecosystems Research, EPRI). Results have been and will be disseminated at the Electric Utilities Environmental Conference (EUEC), and CleanTech Investment conferences (e.g. Clean Technologies and Sustainable Industries Conference; Adriaens co-organizer). Lastly, Prof. Adriaens is President-Elect of the Association of Environmental Engineering and Science Professors (AEESP). During his tenure, he intends to strongly promote technology scalability and the role of engineering-business partnerships, and will increase engagement with professional organizations (e.g. Water Environment Federation) and industry stakeholders.

5.4. K-12 Outreach. A pilot study of campus workplace energy conservation conducted by the UM Institute for Social Research [39] found that young adults are disproportionately high users of electric power. Given that environmental and resource costs of electricity use are concealed to consumers by historical concentration of generation at massive, remote coal-burning power stations, education is crucial to impart an understanding of energy and water interdependence and the benefits of energy and water conservation. Educational outreach will be conducted for students in grades 5-8 of Ann Arbor schools through the Washtenaw County Science Olympiad and Ann Arbor Mathematics Olympiad Cooperative. Lastoskie, who is a coach and volunteer teacher in both organizations, will coordinate K-12 outreach for this project.

6. Impact of the Proposed Research

The importance of achieving domestic energy and water sustainability cannot be overstated. Diversifying condenser technologies and adding redundant resources to thermoelectric cooling will dramatically improve resilience and sustainability in the energy sector and other sectors that depend on freshwater for economic vitality. The broader impact is derived from a novel perspective on the integration of the engineering and business disciplines to address the scalability of (technology-based) solutions, which are inherently uncertain in time and cost, to address environmental sustainability of power production. Sustainability finance is rapidly growing at business schools, as is clean technology development at engineering schools. This project will become part of the body of knowledge to educate engineers and scientists capable of applying business fundamentals to argue value creation from (cooling) technology to utilities.

7. The Research Team

This project brings together expertise in environmental engineering modeling (Lastoskie, Adriaens, LimnoTech) and financial modeling (Kaul) to address investment in water conservation technologies. Prof. Lastoskie will be responsible for the WARMF modeling in consultation with LimnoTech (support letter attached). Prof. Kaul will be responsible for supervising the ROA modeling, and Prof. Adriaens will be responsible for project integration and the correlation analysis between WARMF water flow and temperature projections and water-based derating events. An engineering and business school student will be responsible for the WARMF and ROA modeling, assisted by undergraduate students.

8. Prior NSF Support (Adriaens)

Propagation of Uncertainty in the Field Extrapolation of Laboratory Experiments: Application to Dioxin-Contaminated Sediments. \$250,000 (1999-2002). This project focused on the use of geostatistical approaches to quantify the uncertainty associated with the extrapolation of laboratory-based dechlorination indicators for polychlorinated dibenzo-p-dioxins (PCDD) to contaminated field sediments. One female graduate student (Ph.D.), and two undergraduate students (male/female) were supported, resulting in four publications, six conference presentations and an expert roundtable workshop. The results of the proposal have been leveraged in multiple SERDP grants on spatial and temporal modeling of sediment remediation, and a \$20M+ contract on dioxin exposure pathways, supported by the Dow Chemical Company.

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