Engineering the Implementation of Pumped Hydro

Energy Storage in the Arizona Power Grid

by

William Jesse J. Dixon

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Gerald Heydt, Chair
Kory Hedman
George Karady

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ABSTRACT

This thesis addresses the issue of making an economic case for bulk energy storage in the Arizona bulk power system. Pumped hydro energy storage (PHES) is used in this study. Bulk energy storage has often been suggested for large scale electric power systems in order to levelize load (store energy when it is inexpensive [energy demand is low] and discharge energy when it is expensive [energy demand is high]). It also has the potential to provide opportunities to avoid transmission and generation expansion, and provide for generation reserve margins. As the level of renewable energy resources increases, the uncertainty and variability of wind and solar resources may be improved by bulk energy storage technologies.

For this study, the MATLab software platform is used, a mathematical based modeling language, optimization solvers (specifically Gurobi), and a power flow solver (PowerWorld) are used to simulate an economic dispatch problem that includes energy storage and transmission losses. A program is created which utilizes quadratic programming to analyze various cases using a 2010 summer peak load from the Arizona portion of the Western Electricity Coordinating Council (WECC) system. Actual data from industry are used in this test bed. In this thesis, the full capabilities of Gurobi are not utilized (e.g., integer variables, binary variables). However, the formulation shown here does create a platform such that future, more sophisticated modeling may readily be incorporated.

The developed software is used to assess the Arizona test bed with a low level of energy storage to study how the storage power limit effects several optimization outputs such as the system wide operating costs. Large levels of energy storage are then added to see how high level energy storage affects peak shaving, load factor, and other system applications. Finally, various constraint relaxations are made to analyze why the applications tested eventually approach a constant value.

This research illustrates the use of energy storage which helps minimize the system wide generator operating cost by "shaving" energy off of the peak demand.

The thesis builds on the work of another recent researcher with the objectives of strengthening the assumptions used, checking the solutions obtained, utilizing higher level simulation languages to affirm results, and expanding the results and conclusions.

One important point not fully discussed in the present thesis is the impact of efficiency in the pumped hydro cycle. The efficiency of the cycle for modern units is estimated at higher than 90%. Inclusion of pumped hydro losses is relegated to future work.

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NOMENCLATURE

a	Quadratic Coefficient of the Approximation for the Cost of Generation
A	Coefficient Matrix (m x n) of Inequality Constraints
A	Uniform Amount per Interest Period
A_{eq}	Coefficient Matrix (k x n) of Equality Constraints
A_{quad}	Coefficient Matrix (j x n) of Quadratic Constraints
b	Linear Coefficient of the Approximation for the Cost of Generation
b	Vector (m x 1) of Inequality Right-Hand Side Constraints
b_{eq}	Vector (k x 1) of Inequality Right-Hand Side Constraints
b_{quad}	Vector (j x 1) of Quadratic Right-Hand Side Constraints
B_k	Susceptance of Transmission Element k
c	No Load Coefficient of the Approximation for the Cost of Generation
c	Coefficient of the Cost Function of Generator g
CT	Combined Cycle Power Plant
C_g	Linear Coefficient, b, of the Cost Function of Generator g
ED	Economic Dispatch
E/P	Ratio of Maximum Energy Stored in a Pumped Hydro Energy Storage Facility to the Maximum Power (Rated Power). E is Usually in MWh and P in MW.
EPAct	Energy Policy Act
E_s	Energy Stored in Storage Unit s in MWh
$E_{s,max}$	Maximum Energy Capacity of Storage Unit s in MWh
E_T	Total Energy Supplied in MWh
F_c	Generator Fuel Cost in \$/MBTU

g	Generator Unit
GT	Gas Turbine
i	Interval Number (1, 2, 3, …, 8)
i	Interest Rate per Interest Period
$k(.,n)$	Set of Transmission Assets with n as the "From" Node
$k(n,.)$	Set of Transmission Assets with n at the "To" Node
l	Vector of Lower Bound Variables
LP	Linear Programming
m,n	Bus Number (Nodes)
MIP	Mixed Integer Programming
MILP	Mixed Integer Linear Programming
MIQCP	Mixed Integer Quadratic Constraint Programming
MIQP	Mixed Integer Quadratic Programming
n	Number of Compounding Periods, or Expected Life of an Asset
P	Present Worth, Value, or Amount
P_g	Real Power Output of Generator g in MW
$P_{g,max}$	Maximum Power Capacity of Generator g in MW
$P_{g,min}$	Minimum Power Capacity of Generator g in MW
PHES	Pumped Hydro Energy Storage
P_k	Power Flow of Transmission Line k in MW
$P_{k,max}$	Maximum Line Flow Rating of Transmission Element k in MW
P_l	Active Power of Load l in MW

P_{peak}	Peak Power Demand in MW
P_s	Real Power Output of Storage Unit *s* in MW
$P_{s,max}$	Maximum Power Capacity of Storage Unit *s* in MW
$P_{s,min}$	Minimum Power Capacity of Storage Unit *s* in MW
PV	Photovoltaic
Q_g	Quadratic Coefficient, *a*, of the Cost Function of Generator *g*
QCP	Quadratic Constrained Programming
QP	Quadratic Programming
R_g	Ramp Rate Limit of Generator *g* in MW/h
RPS	Renewable Portfolio Standard
s	Storage Unit
SRP	Salt River Project
ST	Steam Turbine
T	Time Period in Hours
u	Vector of Upper Bound Variables
OM	Generator Operation and Maintenance Costs in $/MWh
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
x	Vector of Generated System Variable Outputs
x_j	Variables that must be Integers
δ_k	Bus Voltage Angle at Bus (Node) *k*
Δt	Length of the Time Interval *i* in Hours

CHAPTER 1: OBJECTIVES RELATING TO PUMPED HYDRO ENERGY STORAGE IN POWER TRANSMISSION SYSTEMS

1.1 Bulk energy storage in Arizona

This research addresses a detailed investigation into the economic justification for bulk energy storage while considering multiple goals which include cost, congestion, and peak shaving for increasing levels of renewable resource penetration. The research specifically uses pumped hydro energy storage (PHES) as the means for bulk energy storage. The test bed used is the Arizona electric power transmission system.

1.2 Motivation for this thesis

A previous study was conducted in 2013 on energy storage for Arizona by Master's candidate John Ruggiero [1]. While the study showed that it was economically feasible to implement PHES into the Arizona grid, many technical assumptions were made. The present thesis focuses on many of those assumptions, and works to make improvements in order to increase the accuracy of the results. A sensitivity study of the results on various assumptions is given. In particular, research objectives for this work include:

- strengthening the assumptions used
- checking the solutions obtained
- utilizing higher level simulation languages to affirm results
- expanding the results and conclusions.

1.3 Bulk energy storage applications

Peak shaving/load leveling

PHES can be used as the means of which to perform peak shaving and load leveling. Peak shaving and load leveling are methods which utilize energy storage in an economic way (in order to save money and resources) by reducing the amount of generation used during high demand hours [2]. For example, electrical energy would be stored when the electrical load is low (cost is low) and discharged when the electrical load is high (cost is high). By doing so, an entity may be able to save money by storing energy (excess generation) when the demand is low and discharging said energy when the demand is high [3].

Peak shaving stores energy during a time in which the system load is low and discharged to remove only the peaks of the load. Peak shaving eliminates the need to use generation from peaking power plants (power plants used only during peak hours). For most load profiles, the system demand is low during morning hours and high in the evening (peak hours). Peak shaving allows generation to be higher in the morning hours, storing the excess generation. This stored energy is then discharged during peak hours so that the peak load is in effect reduced. Figure 1.1 illustrates this idea.

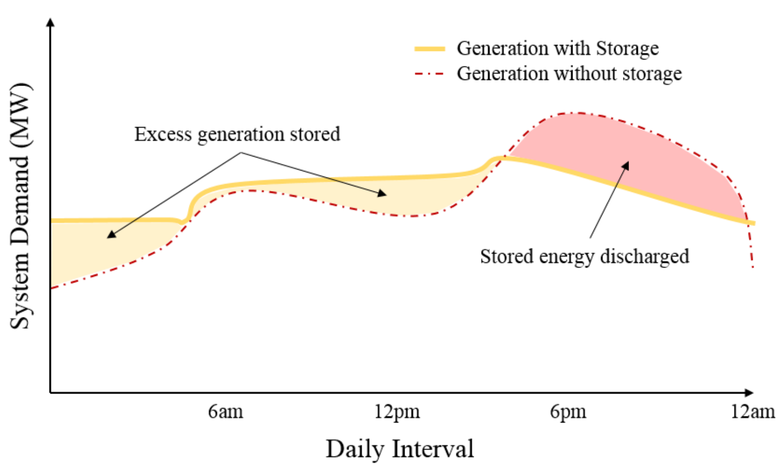

Figure 1.1 Peak Shaving General Diagram

Load leveling is similar to peak shaving where the principal goal is to reduce the generation during peak hours. Load leveling takes this one step further and attempts to flatten the entire load instead of simply "shaving" the peaks [3]. Figure 1.2 illustrates a general load leveling case.

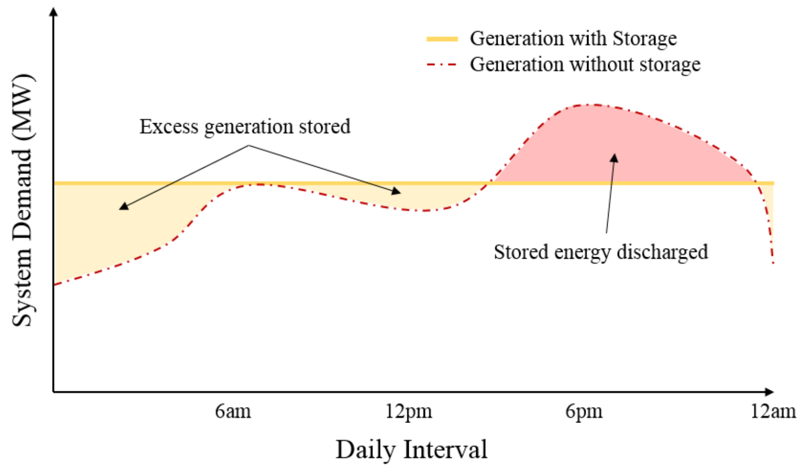

Figure 1.2 Load Leveling General Diagram

Notice the differences between Figures 1.1 and 1.2. The generation profile for peak shaving trends with that of the load, while achieving the main goal of reducing the generation during peak hours. The load leveling case demonstrates the overall goal of "leveling" the generation by storing more energy in the morning hours in order to expel more energy during the peak hours. Load leveling has potential to have a slight economic advantage over peak shaving by allowing generators to stay at a constant power output during the day. Since generator cost curves are generally quadratic, having a consistent medium output is more beneficial than jumping between low and high outputs. The general idea of both peak shaving and load leveling is the same. However, sometimes one method may be more economic than the other.

Transmission expansion deferral

Upgrading the transmission system is a necessity to keep up with the ever increasing demand of electricity. If a new peaking plant is built to keep up with peak loads, transmission will also need to be built to support that new power plant. Another benefit to incorporating energy storage into a grid is the ability to defer or eliminate transmission (and distribution) expansion [4]. A few of these benefits are briefly described below [5].

- **Deferred transmission and distribution upgrade investment:** A single year transmission or distribution deferral benefit is the financial value associated with deferring a utility transmission and distribution upgrade for one year. Essentially, the financial carrying charges are avoided because the upgrade was deferred instead of immediately taken. The savings may be used to finance energy storage support, which later on will accumulate savings on its own.
- **Transmission and distribution equipment life extension:** This is similar to that of a transmission deferral. Use of energy storage reduces the maximum load or load swings on transmission and distribution equipment. Essentially this results in an extension of the equipment's life, the magnitude of the benefit is roughly the same as that of a transmission deferral.
- **Transmission support:** Energy storage has the potential to improve the performance of the transmission system. Energy storage support increases the load carrying capacity of the transmission system (at any location). An accumulated benefit occurs if additional load carrying capacity defers the need to add more transmission or equipment.
- **Avoid transmission access charges:** If a utility does not own transmission lines that are utilized to delivery energy to a customer, they pay the owners of said transmission lines for transmission "service". These charges are called transmission access charges.

- **Reduced cost for line losses:** In most cases, a differential exists between transmission and distribution resistive losses during on and off peak hours. In a purely hypothetical example, if the resistive losses are 10% during peak hours and 6% off peak hours, the avoided losses from implementing storage could be 4% (as long as the storage is located in a reasonably close geographical distance). In effect, this reduces generator fuel consumption and the need for generation and transmission expansion.

Incorporating renewable energy technology

Many of the US states have initiated renewable portfolio standards (RPS) in order to push the development of renewable energy into their systems. Specifically, Arizona’s RPS requires that 15% of all its energy come from renewable resources by the year 2025 [6]. Therefore, it is important to ensure that these renewable resources are reliable and efficient as possible.

Both solar photovoltaics (PV) and wind energy have variable and unpredictable (intermittent) outputs. The sun does not always shine and the wind does not always blow at any given location. This results in a very unlikely scenario that said resources be used as dispatchable (planned ahead for use) generation. The variability of these resources leads to cause of concern regarding the reliability of an electric grid that utilizes a large amount of intermittent resources [7].

Because of these concerns, there is a demand for construction of energy storage systems as an essential component of future electric grids that rely heavily upon renewable energy [8, 9]. Some wind farms have been shown to produce most of their energy during late night and early morning hours (when there is a low demand for electricity) [10]. An energy storage plant (such as PHES) could store this “excess” energy generated by wind farms for use in peak shaving and load leveling cases. This would essentially transfer the energy generated by the wind farms to a more useful hour.

1.4 Bulk energy storage technology - pumped hydro energy storage (PHES)

PHES is one of many types of bulk energy storage technologies that are essential to building a sustainable and efficient electric grid. PHES is currently the best storage technology based on the amount of energy stored (the Castaic PHES facility in California can store water with the equivalent of up to 12.4 GWh [11]). Figure 1.3 illustrates a basic overview of a PHES facility.

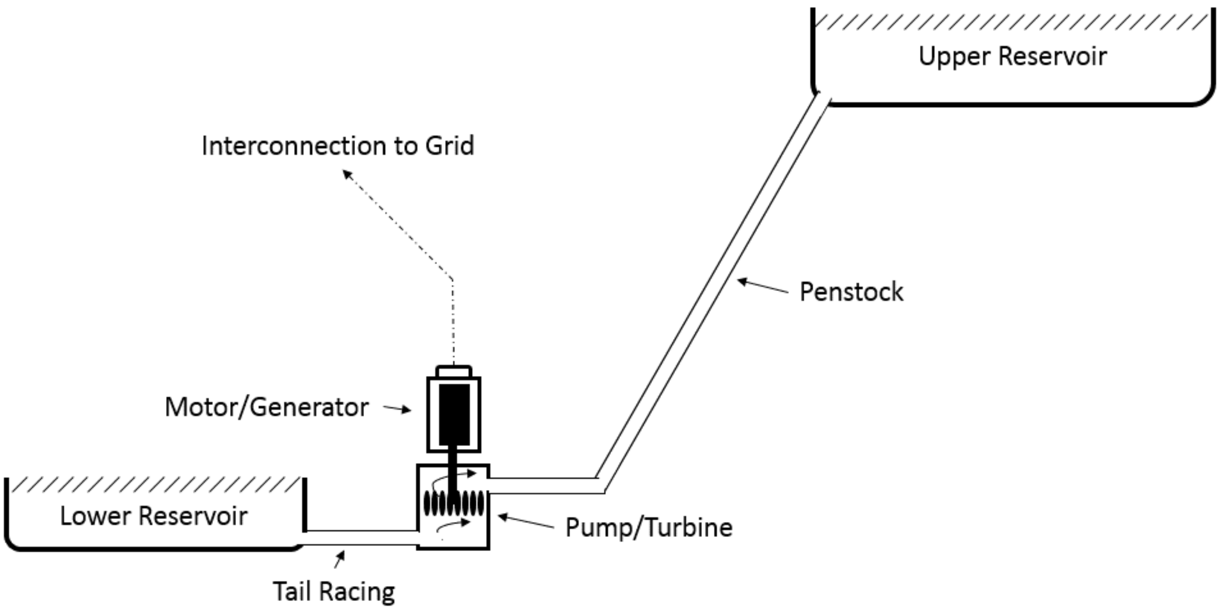

Figure 1.3 A Simple PHES Facility Diagram

A PHES facility essentially stores energy from the grid in the form of transporting water from a low elevation to a high elevation (potential energy). When the electric demand is low (lower cost, during off peak hours), or when there is excess generation available (e.g. renewable resources generating more energy than needed), pump units at a PHES facility are turned on. Water is then transferred from a lower reservoir (e.g. a river, or underground water source [12]) to an upper reservoir (e.g. a lake). The upper reservoir will be located to provide a significant elevation difference from the lower reservoir in order to create a large hydraulic head (pressure). When the electric demand is high (higher cost, during peak hours), the water is transferred from the upper reservoir to the lower reservoir. The water flowing through the penstock operates turbines which provide rotating kinetic energy to synchronous generators [13].

The storage capacity of a PHES facility is dependent on the volume of the reservoirs and the hydraulic head (elevation). Potentially a facility can generate 10-4000MW at an efficiency of 70-80%. Along with energy storage, PHES can be used for peak shaving, spinning reserve, help with transmission expansion, and frequency regulation (in both pumping and generating phases).

1.5 Optimization method

Economic Dispatch

The purpose of economic dispatch (ED) is to minimize the generator cost under a specific set of constraints [14]. According to EPAact, economic dispatch is defined as, "the operating of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operating limits of generation and transmission facilities" [15]. To achieve this, the power output of all generator units must meet the system load demand while conforming to the constraints set on the system. Consequently, this is considered a constrained minimization problem in which the operating cost of generation is minimized subject to constraints such as total generation meeting the load while conforming to power flow rules. Additionally, the constraints include operation within transmission line ratings, contractual and environmental limits. Figure 1.4 illustrates a basic economic dispatch problem. Shown is the input data and prime constraints that minimize the operating cost of the generators.

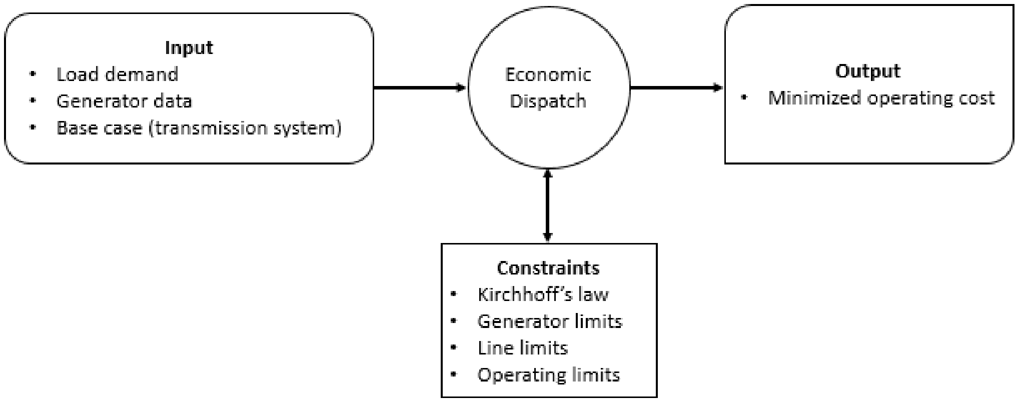

Figure 1.4 Simple Economic Dispatch Problem

Economic dispatch for a thermal unit example

For thermal units, the input-output characteristic is the operating cost function [14]. Fuel consumption is measured in British Thermal Units per hour (BTU/h) or MBTU/h (1 MBTU = 106 BTU). The fuel cost multiplied by the generating fuel consumption is the operating cost, F, in dollars per hour ($/h). *F* for a given generator is often expressed as a quadratic function of the power output (MW) of the unit. The power output of a generator unit is expressed as PG. The operating cost includes fuel, labor, maintenance, and transportation costs. Even if the generator is not supplying power to a load the labor, maintenance, and transportation costs are still a factor and are not a function of P_G. Thus, these costs are represented as a fixed value, or *no load cost*. Figure 1.5 demonstrates the cost curve for a thermal generating unit.

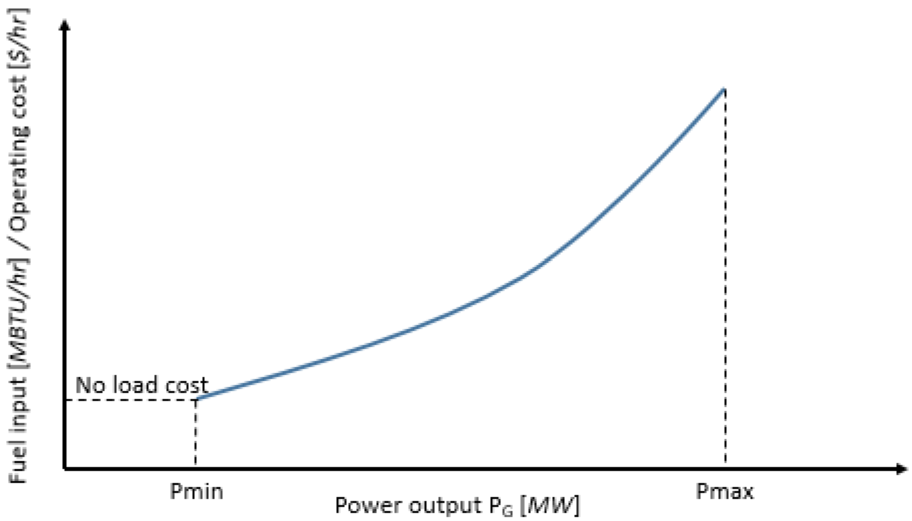

Figure 1.5 Thermal Generator Unit Operating Cost Curve

The term P_{min} (minimum power output) for the thermal generator unit is defined by the operating limits set on the boiler and turbine. The slope of the operating cost can be also called the marginal cost ($/MWh). This is determined by taking the derivative (slope) of the quadratic function used to describe the operating cost. An economic dispatch problem can be formulated via Lagrange Relaxation [16, 17],

$$L(P_i, P_D) = F(P_i) - \lambda \sum_{i=1}^{n} (P_i - P_D) \tag{1.1}$$

where λ is the Lagrange multiplier, n generators, P_i is the power at bus i, and P_D is the total power demand. In the absence of reaching endpoint limitations, and other nonanalytic conditions, the optimum (economic) power output occurs when the derivative of L is zero,

$$\frac{\partial L}{\partial P_i} = 0 \quad \rightarrow \quad \frac{\partial F(P_i)}{\partial P_i} = \lambda, \qquad i = 1, 2, \dots, n \tag{1.2}$$

$$\frac{\partial L}{\partial \lambda} = 0 \Rightarrow \sum_{i=1}^{n} P_i - P_D = 0. \tag{1.3}$$

Under the stated limitations, the optimum occurs when the incremental costs of all generators are equal,

$$\frac{dF_1}{dP_{G1}} = \frac{dF_2}{dP_{G2}} = \cdots \frac{dF_i}{dP_{Gi}} = \lambda \tag{1.4}$$

where $\frac{dF_1}{dP_{G1}}$ is the incremental cost of generator ***i***. Eq. (1.4) is called the *equal incremental cost rule* and is true only when each generator is not in violation of its power limits (P_{min} and P_{max}). The equal incremental cost rule states that at a minimum cost operating point of the system, the incremental cost for all operating generators will be equal. When the demand changes, the generator with the lowest incremental cost will adjust to meet the new demand. When the power output of a generator reaches a limit, the generator is fixed for a demand that would require that generator to violate its set limits. Thus, that generator is no longer a part of the equal incremental cost rule. Generators that have not yet reached their limit will share the demand change based on the equal incremental cost rule.

1.6 Organization of this thesis

This thesis is organized into five chapters and one appendix:

- Chapter 2 delves into the economic dispatch problem and how to solve it.
- Chapter 3 uses the algorithm from Chapter 2 to introduce large amounts of energy storage into the Arizona test bed.
- Chapter 4 discusses the uncertainties from the assumptions made in Chapter 3. A sensitivity study is prepared to investigate effect of these assumptions.
- Chapter 5 presents conclusions and suggests future work related to PHES in Arizona.
- There are three appendices: Appendix A provides the MATLab code used for this research. Appendix B contains graphs from Chapter 4 regarding peak-shaving. Appendix C includes a brief description of Gurobi.

CHAPTER 2: TECHNICAL THEORETICAL BASIS OF BULK ENERGY STORAGE

2.1 Large scale (bulk) energy storage in power systems

The approach taken to determine whether PHES is a feasible means of bulk energy storage in Arizona is relatively straightforward. The system topology (bus, generator, and line information) for Arizona is known. Preliminary research was done to determine realistic locations for adding PHES to the system. The PHES units are added to the system. Energy can now be stored and discharged (utilizing peak shaving/load leveling, refer to Section 1.3) to optimize the total operating cost (cost to run all the generators in the system). An economic dispatch problem is formulated, and the operating cost is minimized to determine the savings from adding PHES to the system. A payback period (number of years required to pay for the construction of the PHES facilities) can be calculated from the savings of adding PHES. This payback period is used to help determine the feasibility of such a project. This chapter discusses, in detail, the formulation of the bulk energy storage problem used in this thesis.

2.2 Economic dispatch methodology

Numerous methods exist and can be used to solve economic dispatch problems. It was determined to use Gurobi Optimizer as the mathematical solver to solve the economic dispatch problem in this thesis. Gurobi was chosen for its numerous features and convenience. Gurobi is a state-of-the-art solver for mathematical programming that includes the following solvers: linear programming (LP), quadratic programming (QP), quadratically constrained programming (QCP), mixed-integer linear programming (MILP), mixed-integer quadratic programming (MIQP), and mixed-integer quadratically constrained programming (MIQCP).

Gurobi has interfaces for C, MATLab, AMPL, and several other programs. This provided a very small learning curve for using Gurobi as MATLab could be used to write the programs. MATLab has easy-to-use matrix sparsity functions, so computational memory would not be an issue (the base case system contains very large data sets that prevent the use of the 32-bit version of AMPL). Gurobi quadratic programming was used to solve the economic dispatch problems in this thesis. PowerWorld was used to incorporate the transmission losses. A discussion on Gurobi appears in Appendix C.

The quadratic programming method contains a quadratic objective rather than a linear objective (as is used in linear programming) [17],

$$Min: x^t Q x + x^t C + \alpha \tag{2.1}$$

where Q is the quadratic objective matrix (quadratic cost terms), C is the linear objective vector (linear cost terms), and α is a set constant (for the purpose of this thesis, $\alpha = 0$). The objective is accompanied with a set of linear constraints (quadratic constraints may be used, see section 2.5),

$$\begin{gathered} A_{eq}x = b_{eq} \\ Ax \leq b \\ lower\ limit \leq x \leq upper\ limit. \end{gathered} \tag{2.2}$$

These constraints govern the rules of the system (e.g. line limits, generator ramp rates, etc.). This method is usually ideal for power system optimization because the generator cost function is often modeled as a quadratic. The objective function is quadratic, thus, the quadratic programming method was determined to be the best option. The formulation of the problem is explained in section 2.3.

2.3 Formulation of the bulk energy storage problem

To obtain an accurate economic dispatch of the system being modeled, a quadratic program is used. The input-output characteristic (cost-curve) of a generating unit is non-linear. The cost curve can be expressed as a quadratic function,

$$F(P_i) = \left(A + BP_i + CP_i^{\ 2}\right)F_C + OMP_i^2 \tag{2.3}$$

where *A*, *B*, and *C* are the coefficients of the input-output characteristic of generator operating with a power output *Pi* [18]. F_c denotes the fuel cost ($/MBTU) and *OM* shows the variable operation and maintenance costs ($/MWh). The coefficients depend on the type of generator and the constant (*A*) is the fuel consumption of the generator at *Pi* = 0 (no-load cost). Table 2.1 shows the cost coefficients for the different types of generators [18]. The following nomenclature is used in Table 2.1:

NG – Natural gas

GT – Gas turbine

ST – Steam turbine

CT – Combined cycle plant

Table 2.1 Generator Cost Coefficients

Generator Cost Coefficients					
Generator Type	Coefficients			Fuel Cost ($/MBTU)	O&M ($/MWh)
	A	B	C		
Nuclear	0	20.000	0.01	0.761	0.220
Coal	0	20.000	0.01	0.720	1.280
NG (GT)	0	12.170	0.01	1.078	0.419
NG (ST)	0	11.270	0.01	1.150	0.225
NG (CC)	0	12.193	0.01	1.091	0.149
Hydro	0	10.000	0.00	1.770	2.280

The values from Table 2.1 can be simplified to a quadratic formulation,

$$F(P_i) = aP_i^{\ 2} + bP_i + c \tag{2.4}$$

where a, b, and c include the constants F_c and OM shown in Table 2.1. Table 2.2 shows the cost coefficients for the generator types (from Table 2.1) converted using the simplified cost curve shown in (2.4). The *quadratic cost* coefficient presented in Table 2.2 refers to the coefficient a, from equation (2.4), while the *linear cost* coefficient refers to the coefficient b. The coefficient c is equal to zero and is not shown in Table 2.2.

Table 2.2 Simplified Cost Curve Coefficients

Simplified Coefficients		
Generator Type	Linear Cost ($/MWh)	Quadratic Cost ($/(MW)^{2}h)
Nuclear	15.44	0.00761
Coal	15.68	0.00720
NG (GT)	13.54	0.01078
NG (ST)	13.19	0.01150
NG (CC)	13.45	0.01910
Hydro	19.91	0

Gurobi is used in conjunction with MATLab to implement the quadratic cost curve (see Section 2.2). For more information on Gurobi refer to Appendix C. The structure of the problem in Gurobi is in the form,

$$min\ f(x) = min \sum_{g} (x^t C_g + x^t Q_g x) \tag{2.5}$$

with the following constraints:

$$A_{ineq} x \leq b_{ineq} \tag{2.6}$$

$$A_{eq} x = b_{eq}. \tag{2.7}$$

The matrix A_{eq} and vector b_{eq} model the *equalities*,

$$\sum_{\forall k(n,.)} P_k - \sum_{\forall k(.\ ,n)} P_k + \sum_{\forall g} P_{g,n} + \sum_{\forall s} P_{s,n} = \sum_{\forall l} P_{l,n}\ \forall n\,, \tag{2.8}$$

$$P_k - B_k(\delta_n - \delta_m) = 0 \quad \forall k, \tag{2.9}$$

$$\sum_{\forall i} P_{s,i} = 0 \quad \forall s. \tag{2.10}$$

The matrix *A* and vector *b* model the *inequalities*,

$$-P_{k,max} \leq P_k \leq P_{k,max} \quad \forall k, \tag{2.11}$$

$$P_{g,min} \leq P_g \leq P_{g,max}; \quad \forall g, \tag{2.12}$$

$$P_{s,min} \leq P_s \leq P_{s,max} \quad \forall s, \tag{2.13}$$

$$0 \leq E_s \leq E_{s,max} \quad \forall s, \tag{2.14}$$

$$-R_g \leq \frac{P_{g,i} - P_{g,i-1}}{\Delta T} \leq R_g \qquad \forall g; \ \forall i \tag{2.15}$$

where the following notation is used:

A_{eq}	Equality Constraint Matrix
A_{ineq}	Inequality Constraint Matrix
b_{eq}	Equality Constraint Condition Vector
b_{ineq}	Inequality Constraint Condition Vector
B_k	Susceptance of Transmission Element *k*
C_g	The Linear Coefficient, *b*, of the Cost Function of Generator *g*
E_s	The Energy Stored in Storage Unit *s* in MWh
$E_{s,max}$	Maximum Energy Capacity of Storage Unit *s* in MWh
f	The Objective Function, Operating Cost
i	Interval Number
k(.,n)	Set of Transmission Assets with *n* as the ‘FROM’ Node
k(n,.)	Set of Transmission Assets with *n* as the ‘TO’ Node
m,n	Bus Number (Nodes)

P_g	The Real Power Output of Generator *g* in MW
$P_{g,max}$	Maximum Power Capacity of Generator *g* in MW
$P_{g,min}$	Minimum Power Capacity of Generator *g* in MW
P_k	The Power Flow of Transmission Line *k* in MW
$P_{k,max}$	Maximum Line Flow Rating of Transmission Element *k* in MW
P_l	The Active Power of Load *l* in MW
P_s	The Real Power Output of Storage Unit *s* in MW
$P_{s,max}$	Maximum Power Capacity of Storage Unit *s* in MW
$P_{s,min}$	Minimum Power Capacity of Storage Unit *s* in MW
Q_g	The Quadratic Coefficient, *a*, of the Cost Function of Generator *g*
R_g	Ramp Rate Limit of Generator *g* in $\frac{MW}{hour}$
δ_k	Bus Voltage Phase Angle at Node *n* or *m*
Δt	Length of Interval *i* in Hours.

The vector *x* includes the bus voltage phase angles (δ), line flows (P_k), generator outputs (P_g), and storage outputs (P_s) for each interval *i*. Note that most studies entail multiple time intervals (e.g., i = 1, 2, …, 24 for a one day study with each interval having a time span of Δt). Most of the quantities listed above need to be specified for each individual time interval, and therefore the notation indicated might also be written with an additional subscript, namely *i*. The equality constraints in matrix A_{eq} and vector b_{eq} include the conservation of power at each bus (2.8), the power flow across each line (2.9), and the charge/discharge of the storage elements (2.10). The inequality constraints in matrix A_{ineq} and vector b_{ineq} include the line flow limits (2.11), generator output limits (2.12), charging power storage limits (2.13), charging energy storage limits (2.14), and the generator ramp rate limits (2.15).

Solving (2.8)-(2.15) gives the optimal $x = x^*$, and also the optimal system wide operating cost $f(x) = f^*$.The operating cost then can be compared using two different models: one including storage and another without storage to evaluate the effectiveness of storage in operating cost reduction. The program is used with a model of the Arizona power grid to demonstrate the benefits of adding pumped hydro energy storage to the system.

2.4 Problem formulation assumptions

In order to solve the economic dispatch problem, a set of assumptions were made in this thesis. The following constraints (introduced in section 2.3) shown in Table 2.3 were observed in the previous thesis by Ruggiero [1].

Table 2.3 Assumptions used in Ruggiero Thesis

John Ruggiero Constraint Conditions and Assumptions [1]
Assumptions
- DCOPF (DC optimum power flow) - Bus voltages assumed 1 per unit
- No transmission losses
- Reactive power is neglected
Constraints (all linear)
- Kirchoffs Law (total power delivered = total power in demand)
- Modeled as DC Power Flow
- Total power taken from storage = total power generated by storage
- Transmission line limits enforced
- Generator power limits enforced
- Storage power limits enforced
- Storage resevoir limits enforced
- Generator ramp rates enforced

Since the primary motivation of this thesis is to improve upon the accuracy of the referenced thesis, a few of the assumptions were changed and included in the study. The key assumption changed was to include transmission line losses. The quadratic programming solver used in Ruggiero's thesis was *Quadprog* (a built-in MATLab function). Unfortunately, *Quadprog* has a lot of limitations, the major one being that no quadratic constraints may be implemented into the economic dispatch problem. Therefore, the mathematical solver *Gurobi* was substituted in for *Quadprog* as it contained several more options that *Quadprog* did not provide. The main feature of Gurobi that was of interest was the ability to implement quadratic constraints to the problem. Refer to Appendix A for the code written in MATLab to utilize Gurobi as the mathematical solver.

Transmission line losses can be modeled as a quadratic constraint (see section 2.5). Table 2.4 lists the assumptions and constraints used in this thesis.

Table 2.4 Assumptions used in this Thesis

William Dixon Constraint Conditions and Assumptions
Assumptions
- DCOPF (DC optimum power flow) - Bus voltages assumed 1 per unit
- Reactive power is neglected (when calculating DCOPF)
- Generator cost terms are realistic (a sensitivity study is provided)
Constraints (linear)
- Kirchoffs Law (total power delivered = total power in demand)
- Modeled as DC Power Flow
- Total power taken from storage = total power generated by storage
- Transmission line limits enforced
- Generator power limits enforced
- Storage power limits enforced
- Storage resevoir limits enforced
- Generator ramp rates enforced
Constraints (quadratic)
- Transmission losses

2.5 Incorporating transmission line losses

Including power losses on transmission lines will have a significant impact on the outcome of the simulation. By using a DC power flow model, a quadratic equation can be made to include as a quadratic constraint in the simulation. By creating this constraint, the simulation will take transmission losses into account, making the final result more accurate. Please note: the following derivation was originally going to be used to consider transmission losses into the system. However, this method was found to not be compatible with Gurobi. The proceeding section discusses the method eventually used to include transmission losses into the system. This derivation is provided for purpose of future work in mind.

The quadratic programming method with Gurobi utilizing quadratic constraints is now used. The objective function is still the same, restated below for convenience,

$$Min: x^t Q x + x^t C + \alpha \tag{2.1}$$

where Q is the quadratic objective matrix (quadratic cost terms), C is the linear objective vector (linear cost terms), and α is a set constant (for the purpose of this thesis, $\alpha = 0$). The objective is accompanied with a set of linear constraints,

$$\begin{gathered} A_{eq}x = b_{eq} \\ A_{ineq}x \leq b_{ineq} \\ lower\ limit \leq x \leq upper\ limit \end{gathered} \tag{2.2}$$

and the constrained optimization is now augmented with a quadratic constraint,

$$x^t A_{quad} x \leq b_{quad} \tag{2.16}$$

where the matrix A_{quad} contains the transmission line loss constraints. The contents to the A_{quad} matrix is derived below.

The basic DC power flow equation model [19, 20] is shown in equation (2.17). Figure 2.1 helps to illustrate (2.17). Note that this is a lossless, lumped parameter model of a transmission line.

$$\frac{V_{ln}^2}{X_{ij}}\left(\delta_i - \delta_j\right) = P_{ij} \quad (2.17)$$

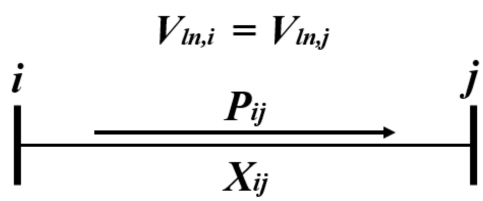

Figure 2.1 DC, lossless, lumped parameter transmission line model, used for power flow analysis

In order to accommodate the simple DC lossless power flow model indicated, the expression (2.17) is used. If quadratic programming is used, then the objective function that captures operating costs must be rendered in quadratic form. In the present calculation, the quadratic programming algorithm used supports optimization of a quadratic objective function subject to linear or quadratic equality constraints.

Equation (2.18) shows that from Ohm's law, the current *I* is known if the power and line voltage is known.

$$\left|I_{[A]}\right| = \frac{P_{per\ \varphi\ [W]}}{V_{\ln[V]}} \quad (2.18)$$

Then, the system wide resistive losses are calculated as,

$$P_{loss\ 3\varphi} = \sum 3|I|^2 R \quad (2.19)$$

where the indicated sun is taken over all transmission lines. Equations (2.18) and (2.19) are combined,

$$P_{loss\ 3\varphi\ [W]} = 3\left|\frac{P_{per\ \varphi\ [W]}}{V_{\ln[V]}}\right|^2 \cdot R_{[\Omega]} \quad (2.20)$$

At this point, because of the potential confusion of per-unit quantities and actual quantities, (2.20) is shown with subscripts that indicate units used. Equation (2.17) is substituted into (2.20),

$$P_{loss\ 3\varphi\ [W]} = 3R_{[\Omega]} \cdot \frac{1}{V_{\ln[V]}^2} \cdot \frac{\left(\delta_i - \delta_j\right)^2 \cdot V_{\ln[V]}^4}{X_{ij\ [\Omega]}^2} \tag{2.21}$$

Equation (2.21) is then simplified, the units are changed to reflect megawatts (MW) instead of watts (W), and the line-neutral voltage (V_{ln}) is changed to line-line (V_{ll}).

$$P_{loss\ 3\varphi\ [MW]} = 3R_{[\Omega]} \cdot \frac{1}{3} \cdot V_{\text{ll}[V]}^2 \frac{\left(\delta_i - \delta_j\right)^2}{X_{ij\ [\Omega]}^2} \cdot 10^{-6} \tag{2.22}$$

Finally, (2.22) is further simplified and the 10^{-6} term is removed by changing the units of the line-line voltage from V to kV (the units are squared),

$$P_{loss\ 3\varphi\ [MW]} = R_{[\Omega]} \cdot V_{\text{ll}[kV]}^2 \frac{\left(\delta_i - \delta_j\right)^2}{X_{ij\ [\Omega]}^2}. \tag{2.23}$$

The power loss equation is now in a quadratic form and may be used as a quadratic constraint in the optimization software.

An alternative for the incorporation of transmission line losses

Due to a limitation in the Gurobi-MATLab interface, adding the quadratic constraints to the program would cause an error because the A_{quad} matrix (containing the transmission line loss quadratic constraints) was not a positive-semi-definite (PSD) matrix [21, 22]. The PSD attribute of the A_{quad} matrix is required by Gurobi-MATLab for quadratic constraints, specifically because Gurobi cannot solve non-convex constraints. PowerWorld Simulator (PW) was used as an alternative solution to incorporate the losses. PW is a power system simulation package that utilizes a robust Power Flow Solution engine capable of efficiently solving very large systems. The PW user manual provides additional information on PW specifics [23].

In order to include the transmission losses in the economic dispatch problem, a combination of the economic dispatch problem written in Gurobi-MATLab and PW is used. By forcing generator power outputs to the pre-solved (no-loss) values, the total losses across the system are assumed to be picked up by the system slack bus. A list of assumptions for the PW configuration are listed in Table 2.5.

Table 2.5 Assumptions made in PowerWorld

PowerWorld ® Assumptions
- Reactive power (VAR) support is given
- The power factor of each generator is forced to 1-0.86 lagging
- Force all generators to a constant power output
- Generator bus voltage set to 1.15 for high load intervals
- Interval 6, 7, and 8
- System slack bus (at Palo Verde) picks up all transmission losses

The following steps are taken to incorporate losses into the economic dispatch calculation:

1. A no-loss version of each case is solved for using the Gurobi-MATLab program
2. A PW case for each interval is created (containing the system topology [transmission line and bus information])
3. The generator data (specifically the power output) for each time interval is taken from step 1 and input into PW, the MW output for each generator is forced to not change
4. The generator per unit voltages are set to 1.15 for high load intervals and the reactive power support for each generator is set to be in a realistic range (1 - 0.86 PF lagging)
5. The AC power flow is solved
6. Whatever the slack bus (at a Palo Verde bus) picks up is considered the total system losses
7. Using a general participation factor for each load interval, the total system losses are taken and dispatched as loads on each generator (and storage unit, if applicable for that interval)
8. These “transmission loss loads” are added to the loads in each case, and the economic dispatch is resolved using the Gurobi-MATLab program

9. The result of the Gurobi-MATLab program now reflects transmission line losses

By following these steps, transmission losses can be incorporated iteratively into the economic dispatch problem. This improves the accuracy of the results.

CHAPTER 3: APPLICATION OF BULK ENERGY STORAGE IN ARIZONA

3.1 Description of the Arizona test bed

This chapter focuses on the presence of bulk energy storage (in the form of PHES) and minimization of the total operating cost (subject to constraints) of the Arizona test bed. The effect of energy storage on the minimization of the objective function (as stated in Section 2.3) is studied. The Arizona electric grid is part of the Western Electricity Coordinating Council (WECC) jurisdiction. Using the Arizona topology, generation limits, transmission limits, and the 2010 heavy summer load case, energy storage is added to appropriate buses in the system and operating results are evaluated. The system data was provided by a state utility, Salt River Project (SRP). The test bed used for this purpose is an equivalent system, including 115 kV and higher transmission voltages.

The objective function (total operating cost in $/day) is minimized while the constraints and formulation of the problem is the same as described in Chapter 2. Figure 3.1 illustrates the principals of this concept.

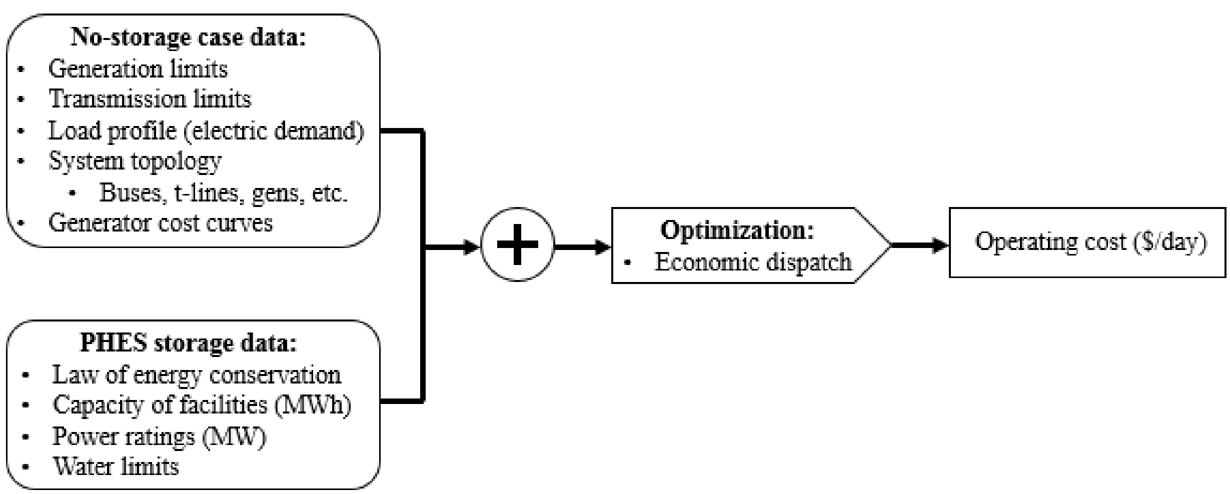

Figure 3.1 Diagram of Concept of Adding PHES to Economic Dispatch Problem

The quadratic programming algorithm explained in Section 2.3 is designed to optimize generation while meeting the load demand at each interval and to schedule energy storage appropriately (in the most economical way possible). The generation, line flow, and energy storage (charging or discharging) schedule are control variables along with the bus voltage angles. These values are calculated and the generation outputs are collaborated with the applicable generation cost curves to determine the system wide operating costs.

The system load used is the Arizona 2010 summer peak, heavy load case. To approximate the time variation of load in a day, the system wide load of 13,627 MW is multiplied by expression (3.1) (this is the same method for approximating the load as was used by Ruggiero in the previous thesis [1]),

$$0.45 \cos\left(\frac{\pi t}{12} + 0.5\pi\right) + 0.55. \tag{3.1}$$

Eight intervals of three hours each are used to replicate the common load profile during a 24 hour day, where t is the time at the beginning of each interval (e.g. t = 0, 3, 6,…, 21). This approximate load profile is shown in Figure 3.2. The objective of the modeled system (depicted in Figure 3.1) is to economically dispatch the available generation while optimally charging or discharging the stored energy (utilizing peak shaving and/or load leveling as described in Section 1.3). The assumptions made for the described test bed are displayed in Table 3.1. The Arizona system is an equivalenced system and this has the characteristics shown in Table 3.2.

Table 3.1 Test Bed Assumptions for this Thesis

Arizona Test Bed Assumptions
- The effects of reactive power are neglected
- Used in the calculation of transmission losses, see Section 2.5
- Bus voltages are all assumed 1 per unit
- Except when calculating transmission losses, see Section 2.5
- Generator cost terms are realistic (sensitivity study provided)
- The DC load flow study approximation is used (DCOPF), specifically the linearization of the sine function near the assumed operating point ($\sin(\theta) \approx \theta$) [17]

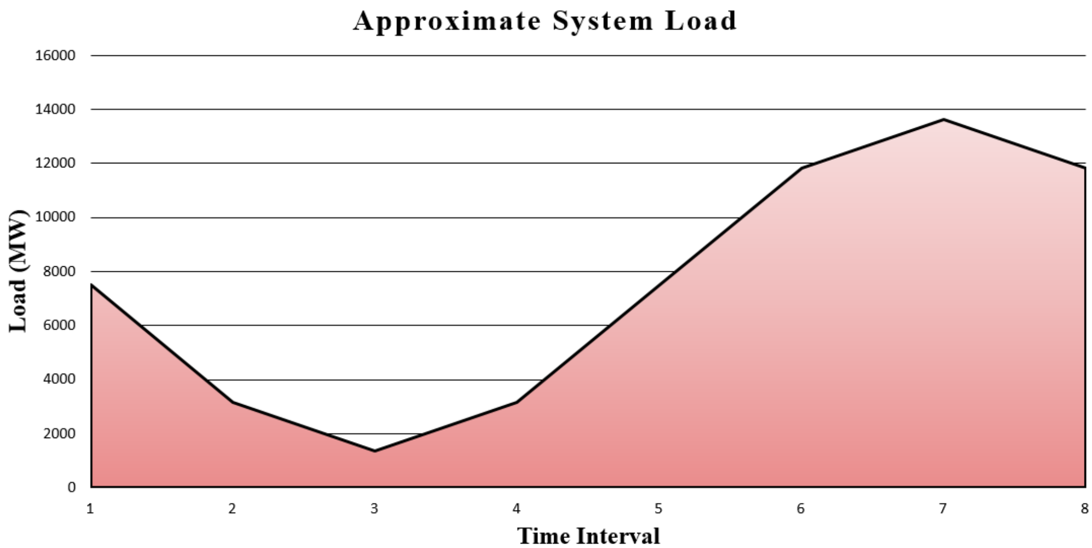

Figure 3.2 Arizona 2010 Summer Peak – Heavy Load Approximation using Piecewise Linear Segments

Table 3.2 System Profile: an Equivalenced System used for this Thesis

Equivalenced Arizona system profile				
Number of buses	Number of transmission lines	Number of generators	Number of time intervals	Duration of each interval [*hours*]
206	277	26	8	3

The quadratic programming algorithm determines the total constrained optimum operating cost of the system. The cost is then multiplied by 365 (days per year) to show the annual system wide operating cost assuming the load modeled is the average over the entire year.

3.2 PHES facility locations

Since PHES was chosen as the form of energy storage for this thesis, preliminary research was done to determine realistic locations for implementing PHES facilities in Arizona. There are two types of locations that will be discussed: theoretical and currently planned.

Theoretical and hypothetical PHES locations

The theoretical (hypothetical, developed as examples assessed from the published literature) locations were chosen for this thesis. Two of these locations are not currently being considered for

PHES but the geographical properties (e.g. elevation differential, nearby water source, existing reservoirs) of each location provide the opportunity to do so in the future. The facility sites were chosen to be near existing hydroelectric dams in Arizona [24, 25].

There is a single pumped hydro facility in use in Arizona at the Horse Mesa Dam located in Maricopa country [26]. The facility is operated by Salt River Project, and the level of energy storage is low. The stated pumped storage power level is 130 MW. The engineering term used for that facility is 'pump back' operation. Both Figure 3.3 and Table 3.5 in Section 3.3 give specific information on the selected theoretical locations. Table 3.3 provides general information on each project.

Table 3.3 Theoretical PHES Projects

Theoretical - Selected PHES Facility Locations in AZ				
Location	**County**	**Nearest bus**	**Water source**	**Operating Entity**
Boulder Dam	Mohave	Mead	Lake Mead	WAPA
Glen Canyon Dam	Coconino	Glen Canyon	Colorado River	WAPA
Horse Mesa Dam	Maricopa	Horse Mesa	Salt River	SRP

Currently planned and potential future PHES locations

These locations were chosen since they are future projects currently awaiting approval from FERC (Federal Energy Regulatory Commission) [27, 28]. Both indicated projects are in the "Issued Preliminary Permits" stage. Both Figure 3.3 and Table 3.5 in Section 3.3 give specific information on the future projects that were selected to model. Table 3.4 provides general information on each project.

Table 3.4 Future Planned PHES Projects

Planned - Selected PHES Facility Locations in AZ				
Location	**County**	**Nearest bus**	**Water source**	**Operating Entity**
Longview	Yavapai	Moenkopi	Ground Water	Longview Energy Exchange
Table Mountain	Mohave	Mead	Colorado River	Table Mountain Hydro

Longview Energy Exchange

This PHES project is currently in the "Issued Preliminary Permits" stage with FERC. Located in Yavapai County, Arizona, the Longview project consists of constructing upper reservoirs and a powerhouse. Around 650 acres of land would be used to host the upper reservoir. Longview uses groundwater as the water source, thus a lower reservoir does not need to be constructed. Underground tunnels will connect the ground water location to the upper reservoir, these tunnels will not be visible above ground. The project reservoirs will be closed loop, meaning that water in the reservoirs will be reusable [29]. The environmental concerns that apply to the Longview project are briefly discussed below:

- The source of water will be locally available ground water coming from the Big Chino aquifer. This aquifer is used downstream by residents in Prescott, Prescott Valley, and Chino Valley Arizona. There is general concern that the use of this water by PHES will affect the water available for residents.
- The Big Chino aquifer supplies 80% of the backflow of the Upper Verde River, which is branded as one of the countries most endangered rivers because it is home to many endangered species. There is concern that these species could be affected if the PHES uses significant resources from that aquifer.

Table Mountain Hydro

This PHES project is currently in the "Issued Preliminary Permits" stage with FERC. Located in Mohave County, Arizona, the Table Mountain project consists of constructing a concrete upper reservoir, lower reservoir, and powerhouse. The upper reservoir has the potential to hold 5,280 acre-ft, with a water surface area of 66 acres. The lower reservoir has similar values. The tunnel connecting both reservoirs is to be above ground. The proposed location will be a closed loop orientation and the circulated reservoir will be reused [30]. An environmental impact study has not yet been performed for this project.

3.3 Description of test cases

The Arizona transmission system described in Section 3.1 is tested using a few different cases. The first case tested is without any energy storage added to the system. This case is analyzed to determine a system wide operating cost that can be used to compare the operating cost of the cases that include PHES.

The cases that include PHES look at locations in Arizona where PHES can be added (in some circumstances, PHES is being already being considered at certain locations). Some of the chosen locations to implement PHES are near existing hydroelectric dams in Arizona (e.g. Hoover (Boulder) Dam, Glen Canyon Dam, and Horse Mesa Dam). PHES does not currently exist at these locations and are used purely for simulation purposes. PHES is placed near existing dams because of the high amount of water and elevation differential in the area. Figure 3.3 shows the locations of the simulated PHES facilities on a map of Arizona.

Specific information about these five PHES locations is provided in Table 3.5. These locations were further discussed in Section 3.2. SRP designates the entity Salt River Project and WAPA designates Western Area Power Administration.

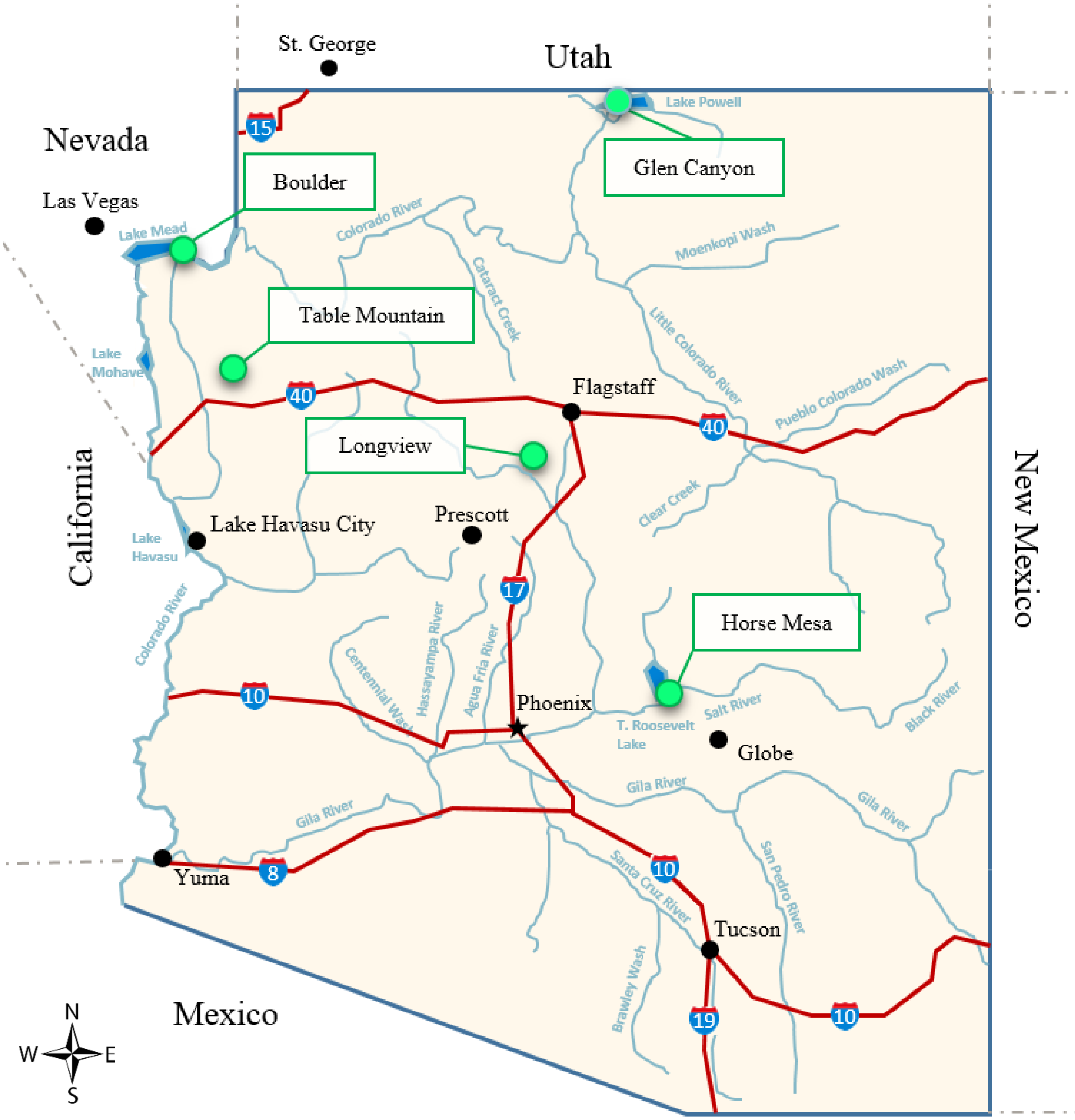

Figure 3.3 Arizona Map with PHES Locations

Table 3.5 Simulated PHES Location Specific Information

Simulated Pumped Hydro Energy Storage Locations							
Location	Power Limit (MW)	Lower reservoir volume (acre-ft)	Lower reservoir surface area (acres)	Lower reservoir avg. depth (ft)	Upper reservoir volume (acre-ft)	Upper reservoir surface area (acres)	Upper reservoir avg. depth (ft)
Boulder	2,080	25,323	265	95.6	24,624	289	85.2
Glen Canyon	1,296	15,778	165	95.6	15,343	180	85.2
Horse Mesa	130	1,583	17	93.1	1,539	18	85.5
Longview	2,000	17,400	175	99.4	17,400	209	83.3
Table Mountain	400	5,683	68	83.6	5,280	66	80

3.4 Arizona base case – summer 2010

The topology (described in Section 3.1) studied with no energy storage is considered the base case (Case 0). The economic dispatch of the generators is determined by solving the quadratic programming algorithm with the Gurobi-MATLab function. To reiterate, in order for the constraints (listed in Section 3.1) to comply, reactive power is neglected (active power losses are considered by the methods explained in Section 2.5). These constraints were previously shown in Table 2.4, and is restated here for convenience.

The cost of ED of generation is calculated to be approximately $3.575 million per day, or $1.305 billion per year. As expected, the total generation output matched the total system load for each interval shown in Figure 3.2 (Section 3.1). The annual system operating cost from this base case (Case 0) will be used for comparison with cases that include bulk energy storage.

Table 2.4 Assumptions used in this Thesis

William Dixon Constraint Conditions and Assumptions
Assumptions
- DCOPF (DC optimum power flow) - Bus voltages assumed 1 per unit
- Reactive power is neglected (when calculating DCOPF)
- Generator cost terms are realistic (a sensitivity study is provided)
Constraints (linear)
- Kirchoffs Law (total power delivered = total power in demand)
- Modeled as DC Power Flow
- Total power taken from storage = total power generated by storage
- Transmission line limits enforced
- Generator power limits enforced
- Storage power limits enforced
- Storage resevoir limits enforced
- Generator ramp rates enforced
Constraints (quadratic)
- Transmission losses

3.5 Arizona pumped hydro energy storage cases

The topology described in Section 3.1 is used again, however nine different cases (varying E/P ratios and generator costs) are studied implementing the plausible locations for PHES in Arizona. The case numbering system is described in Table 3.6. Cases 0', 0", 2, 3, 5, 6, 8, and 9 are discussed later in Chapter 4 as they are affiliated with the sensitivity study. Cases 0, 1, 4, and 7 are essentially the same as cases used in Ruggiero's thesis [1]. Since the primary motivation for this thesis is to compare Ruggiero's results to this thesis', his results are in essence duplicated in Cases 1, 4, and 7. However, this thesis takes transmission losses into consideration (Table 2.5), so a "lossless" case (case with no transmission losses) and a "losses included" (case with transmission losses in the constraints) version of each case is provided (for comparisons) and studied.

Table 3.6 Case Numbering System

Case numbering system				
Gen. Cost Fluctuation	Base case (No Storage)	E/P Ratio 1	E/P Ratio 5	E/P Ratio 10
10%	0"	3	6	9
0%	0	1	4	7
-10%	0'	2	5	8

*0" and 0' refer to the base case with generator costs varied by ±10% respectively

The program created in MATLab is shown in Appendix A. Storage is added to all of the locations shown in Figure 3.3 and listed in Table 3.5. The different test cases study different values of energy to power (E/P) ratios: 1, 5, and 10. Case 0 refers to the base case (a case with no PHES implemented). This ratio describes the size of the upper reservoir, or how much water can be stored. The lower reservoir is assumed to be limitless (therefore the only constraint is the size of the upper reservoir). A higher E/P ratio translates to the reservoir being able to store more water (higher energy (MWh) rating). In effect, the E/P ratio determines how long the PHES facility can provide the rated power (assuming water is previously stored in the upper reservoir). Table 3.7 provides some existing PHES in the United States and their E/P ratios [31].

Table 3.7 Power and Energy Ratings of Selected PHES in the U.S.

PHES facility ratings in the U.S.				
Facility name	Power rating (MW)	Energy rating (MWh)	E/P ratio	Location
Bath County	3003	30030	10	Virginia
Ludington 1872	1872	14976	8	Michigan
Castaic	1427	14270	10	California
Bear Swamp	600	3600	6	Massachusetts
Taum Sauk	440	3520	8	Missouri
Yards Creek	400	2400	6	New Jersey
Cabin Creek	324	1296	4	Colorado
Mount Elbert	200	2400	12	Colorado
Olivenhain-Hodges	40	320	8	California

Table 3.8 shows the different cases studied in this thesis. Each E/P scenario shown is studied for all storage facilities (active in the economic dispatch problem). These three cases are further discussed in the sub-sections that follow.

Table 3.8 PHES Case Scenarios

Pumped hydro energy storage scenarios			
Facility name	E/P ratio	Charging power limit (MW)	Charging energy limit (MWh)
Case 1			
Boulder	1	2080	2080
Glen Canyon	1	1296	1296
Horse Mesa	1	130	130
Longview	1	2000	2000
Table Mountain	1	400	400
Case 2			
Boulder	5	2080	10400
Glen Canyon	5	1296	6480
Horse Mesa	5	130	650
Longview	5	2000	10000
Table Mountain	5	400	2000
Case 3			
Boulder	10	2080	20800
Glen Canyon	10	1296	12960
Horse Mesa	10	130	1300
Longview	10	2000	20000
Table Mountain	10	400	4000

3.5 Payback period calculation

The principal motivation of this thesis is to determine if PHES is an economically feasible means of implementing energy storage into the Arizona electric grid. To determine this, the payback period for building PHES systems into Arizona is of interest. The payback period will give information regarding how long it would theoretically take to effectively "pay for" the PHES facilities. The payback period compares the investment cost of the energy storage with the annual savings. The time period calculated illustrates how long it would take to recover that initial investment. Since the economic dispatch problem will yield an annual operating cost number, the annual savings (from adding bulk energy storage) can be calculated from the base case calculation (Case 0, no energy storage, \$1.305 per year). Using engineering economic principals equation (3.2), the *Uniform Series Present Worth* equation, can be used to determine the payback period given that the annual savings and initial investment is known [32].

$$(P/A, i\%, n) \; = \frac{(1+i)^n - 1}{i(1+i)^n} \tag{3.2}$$

Equation (3.2) states that a present worth *P* (initial investment) can be calculated when the annual payment *A* (annual operating cost savings), annual interest rate *i*, and number of compounding periods *n* (years) is known. *P*, *A*, and *i*, are known, so *n* (the payback period), can be solved for. For the purposes of this thesis, the annual interest rate, *i*, was assumed to be 0.25%.

To estimate the payback period for the PHES facilities used in this thesis, the capital cost (initial investment) needed to be calculated for all of the facilities. There are two costs that go into calculating the total capital cost of the facilities. The power related costs (in \$/kW) include the various pumps and turbines, while the energy related costs (\$/kWh) contain the costs for building the reservoirs. Table 3.9 gives the range of typical power and energy related costs for PHES [18]. These numbers tend to very by location and situation, however they are assumed to be correct since the primary motivation for this thesis was to compare results with that of the thesis by Ruggiero [1].

Table 3.9 Assumed PHES Capital Costs

Typical PHES power and energy related costs		
Type	Minimum	Maximum
Facility power costs (\$/kW)	500	2000
Facility energy costs (\$/kWh)	7	20

Using the values from Tables 3.8 and 3.9, the capital cost of each PHES facility can be calculated for each case. These values are shown in Table 3.10. Since a PHES facility already exists at Horse Mesa Dam, the capital cost did not need to be calculated.

Table 3.10 PHES Facility Initial Investment Costs for Each Case

PHES Facility Capital Costs			
Facility name	E/P ratio	Minimum Cost ($ Billion)	Maximum Cost ($ Billion)
Case 1			
Boulder	1	1.055	4.202
Glen Canyon	1	0.657	2.618
Longview	1	1.014	4.040
Table Mountain	1	0.203	0.808
Total		**2.929**	**11.668**
Case 2			
Boulder	5	1.113	4.368
Glen Canyon	5	0.693	2.722
Longview	5	1.070	4.200
Table Mountain	5	0.214	0.840
Total		**3.090**	**12.130**
Case 3			
Boulder	10	1.186	4.576
Glen Canyon	10	0.739	2.851
Longview	10	1.140	4.400
Table Mountain	10	0.228	0.880
Total		**3.293**	**12.707**

The total PHES capital cost for each case, annual savings for each case, along with equation (3.2) is used to determine the payback period. The payback period for the three case scenarios is later calculated in the proceeding sections after the annual operating savings is calculated for each case.

3.6 Summary of the results

In order to estimate the payback period and make progress towards determining the economic value of PHES in Arizona, the annual operating costs of each case needed to be calculated. The annual operating costs for each case was solved for by implementing the information presented in the previous sections into Gurobi-MATLab (Appendix A).

Case 1 – E/P = 1, unaltered generator cost curves

In Case 1, the storage energy to power ratio (E/P) for each PHES facility was set to 1. Refer back to Table 3.8 for specific information on how the E/P ratio effects the charging energy limit for each PHES facility. The Case 1 data was input into the Gurobi-MATLab program, and the steps outlined in Chapter 2 for implementing transmission losses into the problem were followed. The annual operating cost without and with transmission losses was calculated to be $1.242 billion and $1.305 billion respectively. Adding this PHES to the system resulted (when compared to the base case, Case 0) in an annual savings of $63.0 million for both the lossless case and the case that incorporated losses. The fact that the annual savings resulted in the same value for both cases is simply a coincidence, as will be evident when the E/P ratio changes.

The results without incorporating losses are similar and in agreement with Ruggiero's thesis [1] findings. It is interesting to see that the annual operating cost of the system is increased by 4.02% (~$52 million) when incorporating losses into the problem. The importance of incorporating transmission losses is reflected when the payback period is calculated from these numbers (except for this case). The minimum payback period without and with transmission losses was calculated to be 50 years for both cases. The maximum payback period was calculated to be over 200 years.

To really see the effect of adding PHES to the Arizona grid studied in this thesis, graphs were created to illustrate the peak-shaving (or load-leveling) happening in the system. Refer back to Section 1.3 for information on peak-shaving. Figure 3.4 shows the peak-shaving of Case 1 for the lossless case (no transmission losses considered). Figure 3.5 shows the peak-shaving of Case 1 for the case including losses (transmission losses considered).

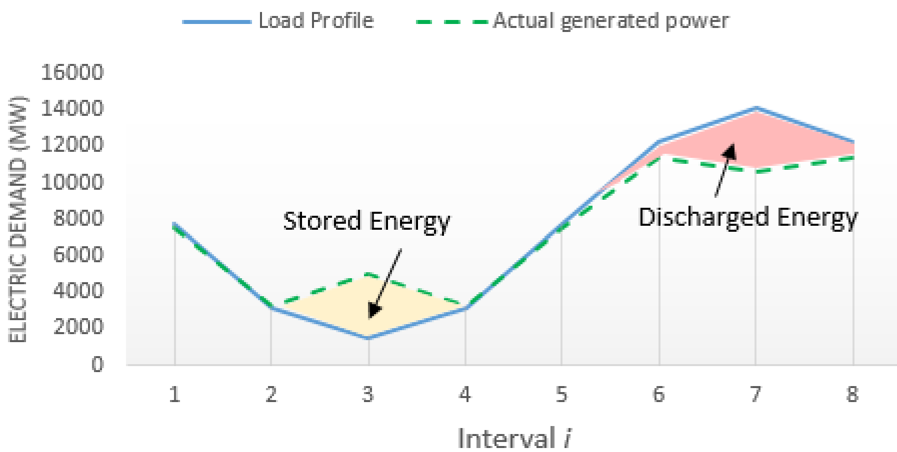

Figure 3.4 Case 1 - Lossless Peak-Shaving

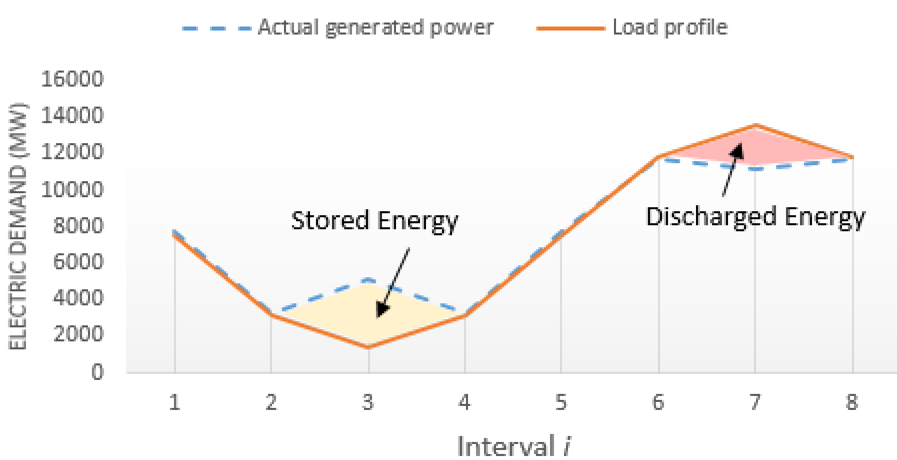

Figure 3.5 Case 1 – Losses Included Peak-Shaving

It is difficult to visually inspect Figures 3.4 and 3.5 to determine the difference incorporating losses has on peak shaving. Figure 3.4 (lossless case) can be seen to have slightly more energy storage utilized for peak-shaving purposes. This is because it is more economical to do so as storing more energy would increase the losses of the system. It is interesting to note that the system automatically attempts to perform peak-shaving, without implementing any constraints in the program that force it to do so. This proves that it is economically beneficial to perform peak-shaving to a system.

Case 4 – E/P = 5, unaltered generator cost curves

In Case 4, the storage energy to power ratio (E/P) for each PHES facility was set to 5. Again, the Case 4 data was input into the Gurobi-MATLab program. The annual operating cost without and with transmission losses was calculated to be $1.192 billion and $1.264 billion respectively. Adding this PHES to the system resulted (when compared to the base case, Case 0) in an annual savings of $113.0 million and $93 million for the lossless case and the case that incorporated losses, respectively. Now that the E/P ratio is not 1 (as it was in Case 1) it can be seen that the annual savings for both the lossless case and losses included case is no longer the same value.

The results without incorporating losses are similar and in agreement with Ruggiero's thesis [1] findings. The annual operating cost of the system is increased by 5.70% (~$72 million) when incorporating losses into the problem. Again, the importance of incorporating transmission losses is reflected when the payback period is calculated from these numbers (except for this case). The minimum payback period without and with transmission losses was calculated to be 29 years and 35 years respectively. The maximum payback period was calculated to be 128 years and 162 years respectively. Now it is apparent how much of an impact losses have on the system; the calculated payback period ranges from 6 to 34 years longer when considering transmission losses.

Again, graphs were created to illustrate the peak-shaving (or load-leveling) happening in the system. Figure 3.6 shows the peak-shaving of Case 4 for the lossless case (no transmission losses considered). Figure 3.7 shows the peak-shaving of Case 4 for the case including losses (transmission losses considered).

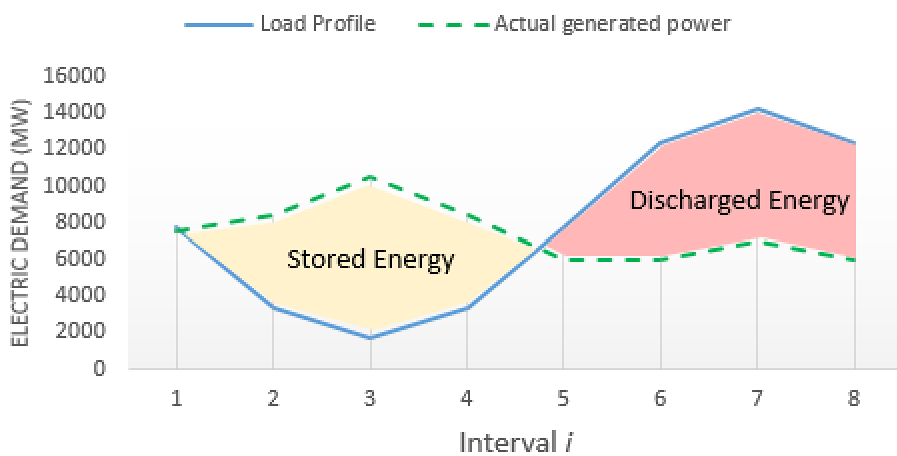

Figure 3.6 Case 4 – Lossless Peak-Shaving

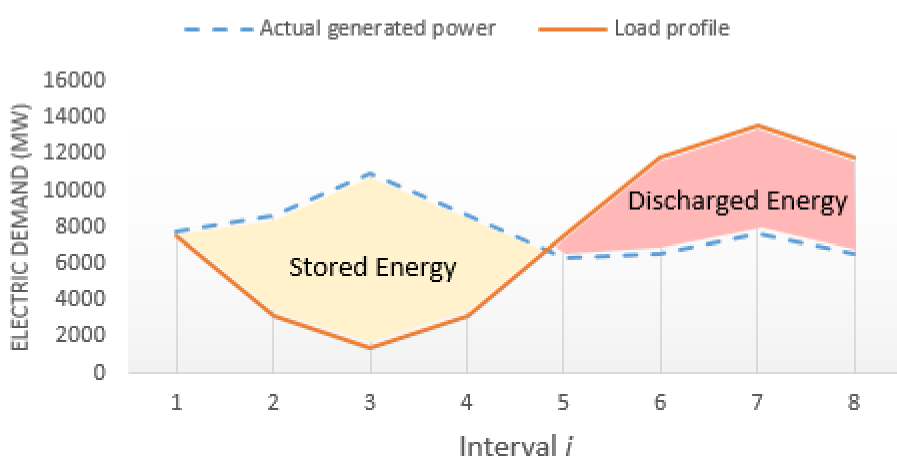

Figure 3.7 Case 4 – Losses Included Peak-Shaving

As was the same result from Case 1, Figure 3.6 (lossless case) can be seen to have slightly more energy storage utilized for peak-shaving purposes than the case that incorporates losses (Figure 3.7). It is interesting to note that Case 4 seems to perform more of a "load-leveling" method than "peak-shaving" method (which was more apparent in Case 1). Again, this proves that it is economically beneficial to perform peak-shaving (in this case, load-leveling) to a system.

Case 7 – E/P = 10, unaltered generator cost curves

In Case 7, the storage energy to power ratio (E/P) for each PHES facility was set to 10. Again, the Case 7 data was input into the Gurobi-MATLab program. The annual operating cost without and with transmission losses was calculated to be $1.185 billion and $1.266 billion respectively. Note that the annual operating cost in the case that includes transmission losses has increased, not decreased, when changing the E/P from 5 to 10. This is due to the program attempting to minimize the cost due to losses. What can be concluded from this, is that a greater E/P ratio does not necessarily correlate to a cheaper annual operating cost. But this was only determined by considering transmission losses.

Adding this PHES to the system resulted (when compared to the base case, Case 0) in an annual savings of $130.0 million and $91 million for the lossless case and the case that incorporated losses, respectively (again note the difference of Case 4 and Case 7).

The results without incorporating losses are similar and in agreement with Ruggiero's thesis [1] findings. The annual operating cost of the system is increased by 6.40% (~$81 million) when incorporating losses into the problem. Again, the importance of incorporating transmission losses is reflected when the payback period is calculated from these numbers (except for this case). The minimum payback period without and with transmission losses was calculated to be 29 years and 38 years respectively. The maximum payback period was calculated to be 126 years and 176 years respectively. Now it is apparent how much of an impact losses have on the system; the calculated payback period ranges from 9 to 50 years longer when considering transmission losses.

Figure 3.8 shows the peak-shaving of Case 7 for the lossless case (no transmission losses considered). Figure 3.9 shows the peak-shaving of Case 7 for the case including losses (transmission losses considered).

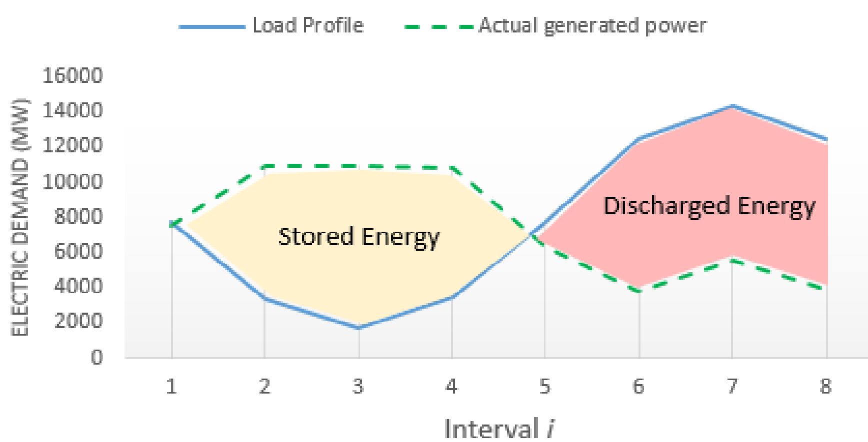

Figure 3.8 Case 7 – Lossless Peak-Shaving

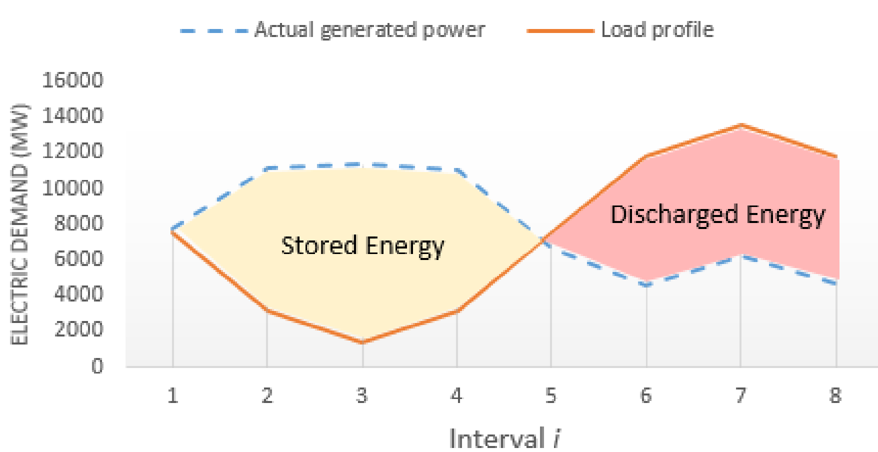

Figure 3.9 Case 7 – Losses Included Peak-Shaving

As was the same result from Case 1 and 4, Figure 3.4 and 3.6 (lossless cases) respectively can be seen to have slightly more energy storage utilized for peak-shaving purposes. It is interesting to note that Case 7 seems to overshoot a load-leveling condition, this is due to more storage being available (E/P = 10) than was in Case 4 (E/P = 5). Once again, this proves that it is economically beneficial to perform peak-shaving (in this case, load-leveling) to a system.

3.7 Conclusions

In Section 3.6, the effects of implementing PHES was studied in 3 different cases (Cases 1, 4, 7). The lossless (transmission losses not considered) essentially reflect Ruggiero's findings [1]. This thesis took the previous thesis one step further and implemented transmission losses into the constraints. The results from Section 3.6 showed that incorporating transmission losses into the calculations is important, as it had a large influence on the annual operating cost, and ultimately, the payback period.

While these results are noteworthy and will assist in justifying the use of PHES in the Arizona power grid, there are a lot of assumptions. One of the primary assumptions of Ruggiero's thesis, is that the generator cost curves for each unit type are realistic numbers. While this may be true, it is impossible to know for certain since the cost curves are confidential and not given out by the entities governing the generators. Chapter 4 provides a sensitivity study of the generator costs.

CHAPTER 4: SENSITIVITY STUDY OF GENERATION COSTS

4.1 Deviation of generator cost curves

One of the primary goals of this thesis was to eliminate the amount of assumptions used. Assumptions may yield results, but a slight tweak in the data (in this case, the generator cost curves) may produce a completely different answer. In order to get a better understanding of the possible effects of the generator cost curve numbers being incorrect, a sensitivity study has been provided to determine how much the generator cost curves impact the economic dispatch problem.

In Section 2.3, Table 2.2 (restated here for convenience) provided the simplified (put into quadratic form) cost curve coefficients for each generator type. The following nomenclature is used in Table 2.2.

NG – Natural gas

GT – Gas turbine

ST – Steam turbine

CT – Combined cycle plant

Table 2.2 Simplified Cost Curve Coefficients

Simplified Coefficients		
Generator Type	Linear Cost ($/MWh)	Quadratic Cost ($/(MW)^{2}h)
Nuclear	15.44	0.00761
Coal	15.68	0.00720
NG (GT)	13.54	0.01078
NG (ST)	13.19	0.01150
NG (CC)	13.45	0.01910
Hydro	19.91	0

A sensitivity study is used to recalculate the data and the results for Cases 0, 1, 4, and 7. Both the linear and quadratic cost coefficients were varied by $\pm$10%. Tables 4.1 and 4.2 show the resultant cost curve coefficients for each type of generator. These new generator cost coefficients (or cost curves) are used in this sensitivity study.

Table 4.1 Simplified Cost Curve Coefficients Varied by +10%

Generator Coefficients +10%		
Generator Type	Linear Cost ($/MWh)	Quadratic Cost ($/(MW)^{2}h
Nuclear	16.98	0.00837
Coal	17.25	0.00792
NG (GT)	14.89	0.01186
NG (ST)	14.51	0.01265
NG (CC)	14.80	0.02101
Hydro	21.90	0

Table 4.2 Simplified Cost Curve Coefficients Varied by -10%

Generator Coefficients -10%		
Generator Type	Linear Cost ($/MWh)	Quadratic Cost ($/(MW)^{2}h
Nuclear	13.90	0.00685
Coal	14.11	0.00648
NG (GT)	12.19	0.00970
NG (ST)	11.87	0.01035
NG (CC)	12.11	0.01719
Hydro	17.92	0

4.2 Description of sensitivity study cases

The topology described in Section 3.1 is used again. However, nine different cases (varying E/P ratios and generator costs) are studied implementing the plausible locations for PHES in Arizona. The case numbering system is described in Section 3.4 in Table 3.4, it is restated below for convenience. Cases 2, 3, 5, 6, 8, and 9 are discussed here in the sensitivity study. Cases 1, 4, and 7 are essentially the same as cases used in Ruggiero's thesis [1] (the lossless cases), and were discussed in Chapter 3. Since the primary motivation of this thesis is to compare Ruggiero's results, they are duplicated in Cases 1, 4, and 7. However, it is desirable to account for transmission losses (Table 2.5). Therefore a "lossless" (case with no transmission losses) and a "losses included” (case with transmission losses in the constraints) version of each case is provided (for comparisons) and studied. Refer back to Chapter 3 for specifics on the locations of the PHES facilities (Section 3.3) and the methods used to solve each test case (Section 3.6).

Table 3.4 Case Numbering System

Case numbering system					
Generator Cost Change	10%	0"	3	6	9
	0%	0	1	4	7
	-10%	0'	2	5	8
		Base case (No Storage)	1	5	10
			E/P Ratio		

*0” and 0’ refer to the base case with generator costs varied by ±10% respectively

4.3 Sensitivity study results

In order to determine the outcome of the sensitivity study and estimate the payback period, the annual operating costs of each case needed to be calculated. The annual operating costs for each case was solved for by implementing the information presented in the previous sections into Gurobi-MATLab (Appendix A). Section 3.6 discussed specifics into the results of each case, a lot of the comments made can be extrapolated and applied here. The graphs that describe the peak-shaving for each case have been provided in Appendix B for desired reference, as they are very similar to those that were presented in Section 3.6.

In each case, the storage energy to power ratio (E/P) for each PHES facility was varied depending on the case; for cases 1-3: E/P = 1, for cases 4-6: E/P = 5, for cases 7-9: E/P = 10. The case specific data were input into the Gurobi-MATLab program, and the steps outlined in Section 2.5 for implementing transmission losses into the problem were followed. The annual operating cost without and with transmission losses was calculated for each case, shown in Tables 4.3 and

4.4 in a convenient manor such that each cases numbers can be compared easily (including the results from Cases 1, 4, and 7). Adding PHES to the system results in an annual savings when compared to the base cases, namely Cases 0, 0', and 0". The annual savings for each case appear in Tables 4.5 and 4.6.

Table 4.3 Calculated System Annual Operating Costs (no Transmission Losses)

Generation operating cost without losses (in billions/year)					
Generator Cost Change	10%	$1.436	$1.367	$1.312	$1.304
	0%	$1.305	$1.242	$1.192	$1.185
	-10%	$1.175	$1.118	$1.073	$1.067
		Base case (No Storage)	1	5	10
			E/P Ratio		

Table 4.4 Calculated System Annual Operating Costs (with Transmission Losses)

Generation operating cost with losses (in billions/year)					
Generator Cost Change	10%	$1.493	$1.423	$1.389	$1.393
	0%	$1.357	$1.294	$1.264	$1.266
	-10%	$1.221	$1.164	$1.137	$1.141
		Base case (No Storage)	1	5	10
			E/P Ratio		

Table 4.5 Calculated System Annual Savings from Adding PHES (no Transmission Losses)

Annual savings without losses (in millions/year)				
Generator Cost Change	10%	$69.0	$124.0	$132.0
	0%	$63.0	$113.0	$130.0
	-10%	$57.0	$102.0	$108.0
		1	5	10
		E/P Ratio		

Table 4.6 Calculated System Annual Savings from Adding PHES (with Transmission Losses)

Annual savings with losses (in millions/year)				
Generator Cost Change	10%	$70.0	$104.0	$100.0
	0%	$63.0	$93.0	$91.0
	-10%	$57.0	$84.0	$80.0
		1	**5**	**10**
		E/P Ratio		

The annual savings can be used to calculate the payback period. Tables 4.7-4.10 provide the calculated minimum and maximum payback period for each case studied.

Table 4.7 Minimum Payback Period (no Transmission Losses)

Payback period without losses ($i = 0.25\%$)				
Generator Cost Change	10%	44	25	25
	0%	49	28	28
	-10%	55	31	31
		1	**5**	**10**
		E/P Ratio		

Table 4.8 Minimum Payback Period (with Transmission Losses)

Payback period with losses ($i = 0.25\%$)				
Generator Cost Change	10%	44	30	34
	0%	49	34	37
	-10%	55	38	43
		1	**5**	**10**
		E/P Ratio		

Table 4.9 Maximum Payback Period (no Transmission Losses)

Payback period without losses (*i* = 0.25%)				
		E/P Ratio		
		1	5	10
Generator Cost Change	10%	200+	112	110
	0%	200+	125	123
	-10%	200+	141	139

Table 4.10 Maximum Payback Period (with Transmission Losses)

Payback period with losses (*i* = 0.25%)				
		E/P Ratio		
		1	5	10
Generator Cost Change	10%	200+	138	153
	0%	200+	158	171
	-10%	200+	179	200+

CHAPTER 5: CONCLUSIONS AND FUTURE WORK

5.1 Conclusions

In this thesis, a test bed utilizing the Arizona transmission system (with a 2010 summer peak load) was used to demonstrate several topics related to bulk energy storage. The following conclusions can be made based on the research and results obtained:

The economic dispatch problem

Chapter 2 contains a discussion of the economic dispatch problem and provided the methodology used to solve the problem. Quadratic programming is chosen as the method to solve the economic dispatch problem and simulate energy storage and its effect on the Arizona power grid.

Addition of energy storage

Chapter 3 shows the calculation of the minimum annual operating cost of the system with no energy storage. Chapters 3 and 4 both discussed the outcome of implementing large levels of PHES in the Arizona power grid. Tables 4.3 and 4.4 (in Section 4.3) state the annual operating costs for all cases. Since adding transmission losses to the problem was a primary motivation of this thesis, Table 5.1 gives a comparison (percent increase) of the “lossless” and “losses included” annual operating costs for each case.

Table 5.1 Annual Operating Cost Percent Increase

Annual operating cost percent increase due to losses				
Generator Cost Change	**No Storage**	**E/P Ratio: 1**	**E/P Ratio: 5**	**E/P Ratio: 10**
10%	3.97%	4.10%	5.87%	6.83%
0%	3.98%	4.19%	6.04%	6.84%
-10%	3.91%	4.11%	5.96%	6.94%

It makes sense that the difference between the "lossless" and "losses included" annual operating costs increased with an increase of the E/P ratio. With an increase in the E/P ratio, the amount of storage being utilized will increase, therefore the losses will increase. In Section 4.3, Tables 4.7-4.10 showed the calculated payback periods for each case. Table 5.2 and 5.3 present the percent increase of the "lossless" and "losses included" payback periods. This percent difference data shows that including transmission losses in the problem formulation and calculation is important. The payback period increased by ~28% in some cases.

Table 5.2 Best Case (Cheapest Storage Costs) Payback Period Percent Increase

Payback period percent increase due to losses				
Generator Cost Change	10%	~ 0%	19.2%	34.6%
	0%	~ 0%	20.7%	31.0%
	-10%	~ 0%	21.9%	37.5%
		1	5	10
		E/P Ratio		

Table 5.3 Worst Case (Most Expensive Storage Costs) Payback Period Percent Increase

Payback period percent increase due to losses				
Generator Cost Change	10%	~ 0%	22.6%	38.9%
	0%	~ 0%	26.6%	39.7%
	-10%	~ 0%	26.9%	39.9%
		1	5	10
		E/P Ratio		

This percent difference data shows that including transmission losses in the problem formulation and calculation is important. The payback period increased by ~28% in some cases.

Sensitivity study – generator cost deviation

One of the primary goals of this thesis was to alleviate the assumptions used. For example, a small variation in generation cost data may result in different conclusions. In order to obtain a better understanding of the effects of the generator cost inaccuracy, a sensitivity study was provided in Chapter 4 to assess the impact on the economic dispatch problem.

After examining the results as indicated in Section 4.3, the percent increase from perturbing the generator cost was calculated. Table 5.4 and 5.5 present the percent increase of the annual operating cost from adjusting the generator costs. This percent increase data shows that fluctuating the generator costs did exactly what was expected. When increasing all of the generator costs by 10% (Cases 3, 6, and 9), the annual operating costs increase by approximately 10% and vice-versa for Cases 2, 5, and 8. The percent increase of the payback period due to changing the generator costs was also calculated and is displayed in Tables 5.6-5.9.

Table 5.4 Percent Increase of Annual Operating Cost from Deviating the Generator Costs

Percent increase of annual operating cost without losses					
Cost Change	10%	10.04%	10.06%	10.07%	10.04%
	-10%	-9.96%	-9.98%	-9.98%	-9.96%
		No Storage	1	5	10
			E/P Ratio		

Table 5.5 Percent Increase of Annual Operating Cost from Deviating the Generator Costs

Percent increase of annual operating cost with losses					
Cost Change	10%	10.02%	9.97%	9.89%	10.03%
	-10%	-10.02%	-10.05%	-10.05%	-9.87%
		No Storage	1	5	10
			E/P Ratio		

Table 5.6 Best Case Payback Period Percent Increase from Deviating the Generator Cost

Percent increase of payback period without losses				
Cost Change	10%	-10%	-10%	-10%
	-10%	12%	10%	10%
		1	5	10
		E/P Ratio		

Table 5.7 Best Case Payback Period Percent Increase from Deviating the Generator Cost

Percent increase of payback period with losses				
Cost Change	10%	-10%	-11%	-8%
	-10%	12%	11%	16%
		1	5	10
		E/P Ratio		

Table 5.8 Worst Case Payback Period Percent Increase from Deviating the Generator Cost

Percent increase of payback period without losses				
Cost Change	10%	0%	-10%	-10%
	-10%	0%	13%	13%
		1	5	10
		E/P Ratio		

Table 5.9 Worst Case Payback Period Percent Increase from Deviating the Generator Cost

Percent increase of payback period with losses				
Cost Change	10%	0%	-13%	-11%
	-10%	0%	14%	14%
		1	5	10
		E/P Ratio		

Note that the payback period actually decreases when the generator costs increase. This is due to the annual savings of implementing PHES increases proportional to the generator cost increase. Observe that (for the worst case) the percent increase in the operating cost is zero with an E/P ratio of 1. This is due to the payback period being out of range of the calculation (listed as 200+, or unfeasible).

Final comments

The research supports the conclusion that the most feasible PHES scenario would be to have an E/P ratio of about 5, as the payback period is the lowest (when including transmission losses). The sensitivity study showed that if the assumed generator costs were inaccurate, the payback period for each case will adjust proportional to the adjustment of the generator costs. For example, if the assumed generation costs are too low (the actual generation costs are 10% higher) then the resulting payback period would be approximately 10% lower than what was originally calculated.

5.2 Future work

In the research and tests performed for this thesis, the economic dispatch was studied using the Arizona test bed with various simplifying assumptions. This thesis in particular, attempted to remove some of the assumptions made by Ruggiero's thesis [1]. However, some assumptions were carried on from the previous thesis, particularly: modeling reactive power flows, energy storage losses, system voltages and their limits. The present engineering study could be enhanced in the following ways:

- One important point not fully discussed in the present thesis is the impact of efficiency in the pumped hydro cycle. The efficiency of the cycle for modern units is estimated at higher than 90%. Inclusion of pumped hydro losses is relegated to future work.
- Performing an ACOPF (unlike the one mentioned in Section 2.5) on the Arizona test bed to model and incorporate bus voltage and transient system stability in an *N*-1 analysis

- Model reactive power in the system analysis and quantify its effects
- Modeling the correct bus voltages in the system
- Extending the analysis out to the entire WECC interconnection and determining PHES locations in the larger system
- Incorporation of examples of lowering the transmission line congestion in the system with implementation of energy storage.

In this thesis, the full capabilities of Gurobi are not utilized (e.g., integer variables, binary variables). However, the formulation shown here does create a platform such that future, more sophisticated modeling may readily be incorporated.

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APPENDIX A

MATLAB CODE

A.1 MATLab code: formulate and solve the economic dispatch for the annual cost

```
% ARIZONA STATE UNIVERSITY
% M.S. Thesis Work
% Student: William J. J. Dixon
% Advisor: Gerald T. Heydt
% Date: Fall 2014
% Purpose: This code puts real data (buses, lines, gens, etc.) into an
%          appropriate matrix form min: x^t*Q*x + C*x in order to calculate
%          a DCOPF. Numerous constraints are included (line limits, gen ramp
%          rates, etc.)

clear

%% Import data
filename = 'Case0_losses_data.xlsx';

%Reads xlsx file with real network data
 A=xlsread(filename,'System data');
  %Determines number of each category
 b=A(1,1);                                       % b=# of buses
 l=A(1,2);                                       % l=# of lines
 g=A(1,3);                                       % g=# of generators
 s=A(1,4);                                       % s=# of storage units
 int=A(1,5);                                     % int=# of load intervals
 dT=A(1,6);                                      % dT= delta t or hours per
interval
 d=A(1,7);                                       % d=number of days
  B=xlsread(filename,'Bus data');       %Extracts bus data
 L=xlsread(filename,'Line data');      %Extracts line data
 G=xlsread(filename,'Generator data'); %Extracts generator data
 S=xlsread(filename,'Storage data');   %Extracts storage data

 X=(3*b+l-1)*int;                              %Creates size of 'x' matrix

 %% Generate Matrices

 %% GENERATION OF THE Q MATRIX (QUADRATIC COSTS)

  %Extracts generator quadratic cost terms and inputs into a matrix
 c=1;
 j=1;
 a=zeros(b,b);
 for k=1:1:g

    a(G(c,1),G(c,1))=G(c,5)*2;
    c=c+1;
    j=j+1;
 end
 %Matrix of generator quadratic costs at each hour
c=1;
j=1;
for k=1:1:int
```

```
    Q1(c:c+b-1,j:j+b-1)=a;
    c=c+b;
    j=j+b;
end
%Overall Q matrix with Q1 in the correct location
Q=zeros(X,X);
Q((b+l-1)*int+1:(2*b+l-1)*int,(b+l-1)*int+1:(2*b+l-1)*int)=Q1;
Q=sparse(Q);

%% GENERATION OF THE C MATRIX (LINEAR COSTS)

%Extracts generator linear cost terms and inputs them into a matrix
c=1;
j=1;
C1=zeros(1,b);
for k=1:1:g

    C1(1,G(c,1))=G(c,4);
    c=c+1;
    j=j+1;
end
%Repeats the linear costs over the amount of hours
j=1;
for k=1:1:int

    CT(1,j:j+b-1)=C1;
    j=j+b;
end
%Inputs the total linear costs into the overall C matrix
C=zeros(1,X);
C(1,(b+l-1)*int+1:(2*b+l-1)*int)=CT;
C=sparse(C);

%% GENERATION OF THE B MATRIX (INEQUALITY LIMITS)

%Generates vector of line limits
c=1;
j=1;
b1=zeros(2*l*int,1);
for k=1:1:l

        b1(c:2*j*int,1)=L(j,6);
        c=c+2*int;
        j=j+1;
end
%Generates vector of generator limits
i=1;
j=1;
b2=zeros(2*b*int,1);
b2i=zeros(2*int,1);
for k=1:1:g
    for u=1:1:int
        b2i(i,1)=G(j,3);
        b2i(i+1,1)=-G(j,2);
        i=i+2;
```

```
    end
    b2(2*G(j,1)*int-(2*int-1):2*G(j,1)*int,1)=b2i;
    j=j+1;
    i=1;
    b2i=zeros(2*int,1);
end
%Generates vector of storage charging power limits
i=1;
j=1;
b3=zeros(2*b*int,1);
b3i=zeros(2*int,1);
for k=1:1:s
    for u=1:1:int
        b3i(i:i+1,1)=S(j,2);
        i=i+2;
    end
    b3(2*S(j,1)*int-(2*int-1):2*S(j,1)*int,1)=b3i;
    j=j+1;
    i=1;
    b3i=zeros(2*int,1);
end
%Generates vector of generator ramp rate limits
i=1;
j=1;
b4=ones(2*b*(int-1),1)*10000;
b4i=zeros(2*(int-1),1);
for k=1:1:g
    for u=1:1:(int-1)
        b4i(i:i+1,1)=G(j,6);
        i=i+2;
    end
    b4(2*G(j,1)*(int-1)-(2*(int-1)-1):2*G(j,1)*(int-1),1)=b4i;
    j=j+1;
    i=1;
    b4i=zeros(2*(int-1),1);
end
%Generates vector of storage charging energy limits
i=1;
j=1;
b5=zeros(2*b*int,1);
b5i=zeros(2*int,1);
for k=1:1:s
    for u=1:1:int
        b5i(i,1)=S(j,3);
        b5i(i+1,1)=0;
        i=i+2;
    end
    b5(2*S(j,1)*int-(2*int-1):2*S(j,1)*int,1)=b5i;
    j=j+1;
    i=1;
    b5i=zeros(2*int,1);
end
%Inputs 5 vectors (b1,b2,b3,b4 and b5) into overall b vector
bT=zeros(2*int*(l+2*b)+2*b*(int-1)+2*b*int,1);
bT(1:2*l*int,1)=b1;
bT(2*l*int+1:2*int*(l+b),1)=b2;
bT(2*int*(l+b)+1:2*int*(l+2*b),1)=b3;
```

```
bT(2*int*(l+2*b)+1:2*int*(l+2*b)+2*b*(int-1),1)=b4;
bT(2*int*(l+2*b)+2*b*(int-1)+1:2*int*(l+2*b)+2*b*(int-1)+2*b*int,1)=b5;
bT=sparse(bT);

%% GENERATION OF THE beq MATRIX (EQUALITY LIMITS)

%Generates beq1 vector which contains the load value at each bus and each
%interval
c=1;
j=1;
m=1;
beqa=zeros(int,1);
beq1=zeros(b*int,1);
for k=1:1:b
        p=5;
    for u=1:1:int
        beqa(c,1)=B(j,p);
        c=c+1;
        p=p+1;
     end
        c=1;
    beq1(m:int*j,1)=beqa;
    m=m+int;
    j=j+1;
end
%Inputs load values into the overall beq vector with zeros at every other
%point
beq=zeros((b+l)*int+b,1);
beq(l*int+1:(l+b)*int,1)=beq1;
beq=sparse(beq);

%% GENERATION OF THE A MATRIX (INEQUALITY CONSTRAINTS)

%Generates the A1 matrix(line inequalities)
t=1;
i=1;
j=1;
m=1;
A1=zeros(2*l*int,l*int);                    %Sets up size of A1 matrix
A1i=zeros(2*int,l*int);                     %Sets up size of inner A1i matrix
for k=1:1:l
    for u=1:1:int
        A1i(i,j)=1;
        A1i(i+1,j)=-1;
        i=i+2;
        j=j+1;
    end
    A1(m:2*t*int,1:l*int)=A1i;                  %Inputs inner matrix of each
    m=m+2*int;                                %line into the larger A1 matrix
    t=t+1;
    i=1;
    j=t;
    A1i=zeros(2*int,l*int);
end;
%Generates the A2 matrix(generator inequalities)
t=1;
```

```
i=1;
j=1;
m=1;
A2=zeros(2*b*int,b*int);                           %Sets up size of A2 matrix
A2i=zeros(2*int,b*int);                            %Sets up size of inner A2i matrix
   for k=1:1:b
         for u=1:1:int
            A2i(i,j)=1;
            A2i(i+1,j)=-1;
            i=i+2;
            j=j+b;
   end
   A2(m:2*t*int,1:b*int)=A2i;
   m=m+2*int;
   t=t+1;
   i=1;
   j=t;
   A2i=zeros(2*int,b*int);
   end
%Generates A3 matrix (storage inequalities)
t=1;
i=1;
j=1;
m=1;
A3=zeros(2*b*int,b*int);                           %Sets up size of A3 matrix
A3i=zeros(2*int,b*int);                            %Sets up size of inner A3i matrix
for k=1:1:b
    for u=1:1:int
        A3i(i,j)=1;
        A3i(i+1,j)=-1;
        i=i+2;
        j=j+b;
    end
    A3(m:2*t*int,1:b*int)=A3i;                         %Inputs inner matrix of each
    m=m+2*int;                                       %storage into the larger A3
matrix
    t=t+1;
    i=1;
    j=t;
    A3i=zeros(2*int,b*int);
end;
%Generates the A4 matrix(generator ramp rate inequalities)
i=1;
j=1;
m=1;
t=1;
A4=zeros(2*b*(int-1),b*int);
A4i=zeros(2*(int-1),b*int);
for k=1:1:b
    for u=1:1:(int-1)
        A4i(i,j)=1/dT;
        A4i(i,j+b)=-1/dT;
        A4i(i+1,j)=-1/dT;
        A4i(i+1,j+b)=1/dT;
        i=i+2;
        j=j+b;
    end
```

```
    A4(m:2*t*(int-1),1:b*int)=A4i;
    m=m+2*(int-1);
    t=t+1;
    i=1;
    j=t;
    A4i=zeros(2*(int-1),b*int);
end
%Generates the A5 matrix (bulk energy storage limit on energy storage)
i=1;
j=1;
t=0;
z=1;
f=1;
y=int;
A5=zeros(2*b*int,b*int);
A5i=zeros(2*int,b*int);
for k=1:1:b
    for m=1:1:int
        for u=1:1:y
            A5i(i+2*t,j)=dT;
            A5i(i+2*t+1,j)=-dT;
            i=i+2;
        end
        i=1;
        y=y-1;
        t=t+1;
        j=j+b;
    end
    A5(f:2*z*int,1:b*int)=A5i;
    y=int;
    f=f+2*int;
    z=z+1;
    j=z;
    t=0;
    A5i=zeros(2*int,b*int);
end
%Stores each of the smaller matrices (A1,A2,A3,A4, and A5) into the A matrix
A=zeros(2*int*(l+2*b)+2*b*(int-1)+2*b*int,X);
A(1:2*l*int,(b-1)*int+1:(b+l-1)*int)=A1;
A(2*l*int+1:2*int*(l+b),(b+l-1)*int+1:(2*b+l-1)*int)=A2;
A(2*int*(l+b)+1:2*int*(l+2*b),(2*b+l-1)*int+1:X)=A3;
A(2*int*(l+2*b)+1:2*int*(l+2*b)+2*b*(int-1),(b+l-1)*int+1:(2*b+l-1)*int)=A4;
A(2*int*(l+2*b)+2*b*(int-1)+1:2*int*(l+2*b)+2*b*(int-1)+2*b*int,(2*b+l-
1)*int+1:X)=A5;
%A=sparse(A);

%% GENERATION OF THE AEQ MATRIX (EQUALITY CONSTRAINTS)

Aeq=zeros((b+l)*int+s,X);                %Sets up the size of the Aeq matrix
%GENERATION OF AEQ1A MATRIX(LINE DELTA VALUES)
p=1;
t=1;
i=1;
j=0;
m=1;
```

```
Aeq1a=zeros(l*int,b*int);                    %Sets up the size for the Aeq1a
matrix
Aeq1ai=zeros(int,b*int);                     %Sets up the size for the Aeq1ai
matrix
for k=1:1:l
    kV2=B(L(p,2),4)*B(L(p,3),4);
    for u=1:1:int
        if (L(p,2)< L(p,3))
            Aeq1ai(i,L(p,2)+j)=-kV2/L(p,5);
            Aeq1ai(i,L(p,3)+j)=kV2/L(p,5);
            i=i+1;
            j=j+b;
        elseif (L(p,2) > L(p,3))
            Aeq1ai(i,L(p,2)+j)=kV2/L(p,5);
            Aeq1ai(i,L(p,3)+j)=-kV2/L(p,5);
            i=i+1;
            j=j+b;
        end
    end
    Aeq1a(m:t*int,1:b*int)=Aeq1ai;
    m=m+int;
    t=t+1;
    Aeq1ai=zeros(int, b*int);
    i=1;
    p=p+1;
    j=0;
end
%Deletes the swing bus because it has an angle of zero
i=1;
j=0;
for k=1:1:b
    if B(i,2)==3
        for u=1:1:int
            Aeq1a(:,B(i,1)+j)=[];
            j=j+b-1;
        end
    end
     i=i+1;
end
Aeq(1:l*int,1:(b-1)*int)=Aeq1a; %Stores the line delta values in the Aeq
matrix
%GENERATION OF AEQ1B MATRIX (LINE POWER FLOW VALUES)
m=1;
i=1;
j=1;
t=1;
Aeq1b=zeros(l*int,l*int);                    %Sets up the size for the Aeq1b
matrix
Aeq1bi=zeros(int,l*int);                     %Sets up the size for the Aeq1bi
matrix
for k=1:1:l
    for u=1:1:int
        Aeq1bi(i,j)=1;
        i=i+1;
        j=j+l;
    end
    Aeq1b(m:t*int,1:l*int)=Aeq1bi;
```

```
    m=m+int;
    t=t+1;
    j=t;
    i=1;
    Aeq1bi=zeros(int,l*int);
end
Aeq(1:l*int,(b-1)*int+1:(b+l-1)*int)=Aeq1b; %Stores the Aeq1b matrix into Aeq
%GENERATION OF THE AEQ2A MATRIX(BUS POWER FLOW VALUES)
i=1;
j=0;
t=1;
e=1;
m=1;
Aeq2a=zeros(b*int,l*int);                      %Sets up the Aeq2a matrix size
Aeq2ai=zeros(int,l*int);
for k=1:1:b
    for u=1:1:l
        if ((L(i,2)== t) || (L(i,3) == t))  %Tests to see if a line contains
a bus number
 %Determines which way power is flowing based on order of buses
            for v=1:1:int
                if L(i,2)==t
                    Aeq2ai(e,L(i,1)+j)=-1;
                elseif L(i,3)==t
                    Aeq2ai(e,L(i,1)+j)=1;
                end
                e=e+1;
                j=j+l;
            end
            j=0;
            e=1;
        end
        i=i+1;
    end
        Aeq2a(m:t*int,1:l*int)=Aeq2ai;
        m=m+int;
        t=t+1;
        i=1;
        j=0;
        e=1;
        Aeq2ai=zeros(int,l*int);
end
Aeq(l*int+1:(l+b)*int,(b-1)*int+1:(b+l-1)*int)=Aeq2a;   %Stores Aeq2a into
Aeq
%GENERATION OF THE AEQ2B MATRIX (BUS GENERATION VALUES)
i=1;
j=1;
t=1;
m=1;
Aeq2b=zeros(b*int,b*int);                      %Sets up the size of the Aeq2b
matrix
Aeq2bi=zeros(int,b*int);
for k=1:1:b
        for u=1:1:int
            Aeq2bi(i,j)=1;
            j=j+b;
            i=i+1;
```

```
        end
    Aeq2b(m:t*int,1:b*int)=Aeq2bi;
    m=m+int;
    t=t+1;
    i=1;
    j=t;

    Aeq2bi=zeros(int,b*int);
end
Aeq(l*int+1:(l+b)*int,(b+l-1)*int+1:(2*b+l-1)*int)=Aeq2b; %Stores it in the
Aeq matrix
%GENERATION OF THE AEQ2C MATRIX(BUS STORAGE VALUES)
i=1;
j=1;
t=1;
Aeq2c=zeros(b*int,b*int);                %Sets up the size of the Aeq2c matrix
%Aeqxi=zeros(int,b*int);
for k=1:1:b
    for u=1:1:int
        Aeq2c(i,j)=-1;
        i=i+1;
        j=j+b;
    end
    t=t+1;
    j=t;
end
Aeq(l*int+1:(l+b)*int,(2*b+l-1)*int+1:(3*b+l-1)*int)=Aeq2c;   %Stores the
Aeq2c matrix into Aeq
%GENERATION OF THE AEQ3 MATRIX(STORAGE VALUES AT EACH HOUR)
i=1;
j=1;
Aeq3=zeros(b,b*int);
for k=1:1:b
    for u=1:1:int
        Aeq3(i,j)=1;
        j=j+b;
    end
    i=i+1;
    j=i;
end
Aeq((l+b)*int+1:(l+b)*int+b,(2*b+l-1)*int+1:(3*b+l-1)*int)=Aeq3; %Stores the
Aeq3 matrix into the Aeq matrix
Aeq=sparse(Aeq);

%% Run Optimization

% Ensure sparsity
Q = sparse(Q);
A = sparse(A);
C = full(C);
Aeq = sparse(Aeq);
bT = full(bT);
beq = full(beq);

% Set up Gurobi model
model.Q = 0.5*Q;
```

```
model.obj = C;
model.A = [A; Aeq];
model.rhs = [bT; beq];
model.sense = [repmat('<', size(A,1), 1); repmat('=', size(Aeq,1),1)];
model.objcon = 0;

% Set upper and lower bounds of X to +- infinity
model.lb = -inf(size(A,2),1);
model.ub = inf(size(A,2),1);

% Solver method
params.method = 0; % Primal Simplex Method (for MIQP)

% Solve Gurobi model
result = gurobi(model);

Cost=result.objval*dT*d

x = result.x;

%Extracts line flows at each interval
x1=x(int*(b-1)+1:int*(b-1)+l);
x2=x(int*(b-1)+l+1:int*(b-1)+2*l);
x3=x(int*(b-1)+2*l+1:int*(b-1)+3*l);
x4=x(int*(b-1)+3*l+1:int*(b-1)+4*l);
x5=x(int*(b-1)+4*l+1:int*(b-1)+5*l);
x6=x(int*(b-1)+5*l+1:int*(b-1)+6*l);
x7=x(int*(b-1)+6*l+1:int*(b-1)+7*l);
x8=x(int*(b-1)+7*l+1:int*(b-1)+8*l);
%Extracts generator output at each interval
y1=x(int*(l+b-1)+1:int*(l+b-1)+b);
y2=x(int*(l+b-1)+b+1:int*(l+b-1)+2*b);
y3=x(int*(l+b-1)+2*b+1:int*(l+b-1)+3*b);
y4=x(int*(l+b-1)+3*b+1:int*(l+b-1)+4*b);
y5=x(int*(l+b-1)+4*b+1:int*(l+b-1)+5*b);
y6=x(int*(l+b-1)+5*b+1:int*(l+b-1)+6*b);
y7=x(int*(l+b-1)+6*b+1:int*(l+b-1)+7*b);
y8=x(int*(l+b-1)+7*b+1:int*(l+b-1)+8*b);
%Extracts storage output at each interval
z1=x(int*(l+2*b-1)+1:int*(l+2*b-1)+b);
z2=x(int*(l+2*b-1)+b+1:int*(l+2*b-1)+2*b);
z3=x(int*(l+2*b-1)+2*b+1:int*(l+2*b-1)+3*b);
z4=x(int*(l+2*b-1)+3*b+1:int*(l+2*b-1)+4*b);
z5=x(int*(l+2*b-1)+4*b+1:int*(l+2*b-1)+5*b);
z6=x(int*(l+2*b-1)+5*b+1:int*(l+2*b-1)+6*b);
z7=x(int*(l+2*b-1)+6*b+1:int*(l+2*b-1)+7*b);
z8=x(int*(l+2*b-1)+7*b+1:int*(l+2*b-1)+8*b);
```

A.2 MATLab code: extrapolate generator data and export into a form usable by PowerWorld

```
% Arizona State University
% Name: William J Dixon
% Date: Fall 2014
% Topic: MS Thesis
```

```
% Purpose: Take X data after running Dixon_LargeSystemv3edit.m
%          to get Gen and Storage data out of it

% Output file name
fname = 'Case1_Gen_Data_PW.xlsx';

X=x;
% x_vector_marginal_x
% x_vector_no_losses
% x_vector_losses

%% Initialize
int_num = 8; % Number of integers
bus_num = 206; % Number of buses
i = 0; % Incrementing variable
j = 0; % Incrementing variable

% Generator Bus Index
index_gens = [1 2 4 8 9 11 17 23 45 55 56 59 61 62 63 64 83 90 103 ...
    106 117 132 140 141 186 187];

% Storage Unit Bus Index
index_stor = [3 83 149 153 186];

% Number of generators and storage units
num_gens = size(index_gens,2);
num_stor = size(index_stor,2);

%% Generators
for int = 1:int_num
    for bus = 1:bus_num
        gens(bus,int) = X(3857+(bus-1)+(int-1)*bus_num);
    end
end

for int = 1:int_num
    for index = 1:num_gens
        Gens(index,int) = gens(index_gens(index),int);
    end
end

%% Storage
for int = 1:int_num
    for bus = 1:bus_num
        storage(bus,int) = X(5505+(bus-1)+(int-1)*bus_num);
    end
end

for int = 1:int_num
    for index = 1:num_stor
        Storage(index,int) = storage(index_stor(index),int);
    end
end

Storage = Storage * -1;
```

```matlab
%% Total generation per interval

for int = 1:int_num
        Total_gen_int(int) = sum(Gens(:,int));
    for i = 1:size(Storage,1)
        if Storage(i,int) > 0
            Total_gen_int(int) = Total_gen_int(int) + Storage(i,int);
        end
    end
end

Total_gen = sum(Total_gen_int);



%% Writes to Excel file in Power World format to calculate losses in PW

for j = 1:int_num
    genNstor(1,j) = Gens(1,j);
    genNstor(2,j) = Gens(2,j);
    genNstor(3,j) = Storage(1,j);
    genNstor(4,j) = Gens(3,j);
    genNstor(5,j) = Gens(4,j);
    genNstor(6,j) = Gens(5,j);
    genNstor(7,j) = Gens(6,j);
    genNstor(8,j) = Gens(7,j);
    genNstor(9,j) = Gens(8,j);
    genNstor(10,j) = Gens(9,j);
    genNstor(11,j) = Gens(10,j);
    genNstor(12,j) = Gens(11,j);
    genNstor(13,j) = Gens(12,j);
    genNstor(14,j) = Gens(13,j);
    genNstor(15,j) = Gens(14,j);
    genNstor(16,j) = Gens(15,j);
    genNstor(17,j) = Gens(16,j);
    genNstor(18,j) = Gens(17,j);
    genNstor(19,j) = Storage(2,j);
    genNstor(20,j) = Gens(18,j);
    genNstor(21,j) = Gens(19,j);
    genNstor(22,j) = Gens(20,j);
    genNstor(23,j) = Gens(21,j);
    genNstor(24,j) = Gens(22,j);
    genNstor(25,j) = Gens(23,j);
    genNstor(26,j) = Gens(24,j);
    genNstor(27,j) = Storage(3,j);
    genNstor(28,j) = Storage(4,j);
    genNstor(29,j) = Gens(25,j);
    genNstor(30,j) = Storage(5,j);
    genNstor(31,j) = Gens(26,j);
end

xlswrite(fname,genNstor(:,1),1,'E3')
xlswrite(fname,genNstor(:,2),2,'E3')
xlswrite(fname,genNstor(:,3),3,'E3')
xlswrite(fname,genNstor(:,4),4,'E3')
```

```
xlswrite(fname,genNstor(:,5),5,'E3')
xlswrite(fname,genNstor(:,6),6,'E3')
xlswrite(fname,genNstor(:,7),7,'E3')
xlswrite(fname,genNstor(:,8),8,'E3')
```

A.3 MATLab code: add loss data to the original data file

```
% Arizona State University
% Name: William J Dixon
% Date: Fall 2014
% Topic: MS Thesis
% Purpose: Take Gen data after running it through PW to get loss data, add
%          the losses as loads on each generator according to a
%          participation factor

%% Input
%%% File names %%%
% Loss data obtained after PowerWorld run
loss_name = 'Case1_Loss_Data_PW.xlsx';
% Data before PowerWorld run (after runnning Thesis_Gens_data.m)
no_loss_name = 'Case1_Gen_Data_PW.xlsx';
% Data file (containing line, bus, gen, storage information)
file_name = 'Case1_data.xlsx';
% New data file
final_name = 'Case1_losses_data.xlsx';

% Read in Gen Data that came from PW
Gen_loss(:,1) = xlsread(loss_name,1,'E3:E33');
Gen_loss(:,2) = xlsread(loss_name,2,'E3:E33');
Gen_loss(:,3) = xlsread(loss_name,3,'E3:E33');
Gen_loss(:,4) = xlsread(loss_name,4,'E3:E33');
Gen_loss(:,5) = xlsread(loss_name,5,'E3:E33');
Gen_loss(:,6) = xlsread(loss_name,6,'E3:E33');
Gen_loss(:,7) = xlsread(loss_name,7,'E3:E33');
Gen_loss(:,8) = xlsread(loss_name,8,'E3:E33');

int_num = 8;

% Generator Bus Index
index_gens = [1 2 4 8 9 11 17 23 45 55 56 59 61 62 63 64 83 90 103 ...
    106 117 132 140 141 186 187];

% Storage Unit Bus Index
index_stor = [3 83 149 153 186];

% Slack Bus
slack_index = 63; % Palo Verde 3
slack = 16; % The 16th entry is bus 63, Palo Verde 3

Gen(:,1) = xlsread(no_loss_name,1,'E3:E33');
Gen(:,2) = xlsread(no_loss_name,2,'E3:E33');
Gen(:,3) = xlsread(no_loss_name,3,'E3:E33');
Gen(:,4) = xlsread(no_loss_name,4,'E3:E33');
```

```
Gen(:,5) = xlsread(no_loss_name,5,'E3:E33');
Gen(:,6) = xlsread(no_loss_name,6,'E3:E33');
Gen(:,7) = xlsread(no_loss_name,7,'E3:E33');
Gen(:,8) = xlsread(no_loss_name,8,'E3:E33');

% Find the total losses for each interval
% AND the total generation (NOT including storage if in pumping stage)
for i = 1:size(Gen,2) % for # intervals
    k = 1;
    for j = 1:size(Gen,1) % for # of generators
        if Gen(j,i) >= 0 % if the "generator" is producing power
            Gens(k,i) = Gen(j,i); % Put value into new variable, "Gens"
            k = k + 1;
        end
    end
    loss(i) = Gen_loss(slack,i) - Gen(slack,i);
    total_gen(i) = sum(Gens(:,i));
end

% Find the participation factor for each generator at each interval
for i = 1:size(Gen,2)
    for j = 1:size(Gen,1)
        if Gen(j,i) >= 0
            P_factor(j,i) = Gen(j,i)/total_gen(i);
        elseif Gen(j,i) < 0
            P_factor(j,i) = 0;
        end
    end
end

% Find the Gen contribution to the losses, or how much each generator
% should generate in order to compensate for the losses
for i = 1:size(Gen,2)
    for j = 1:size(Gen,1)
        load(j,i) = P_factor(j,i)*loss(i);
    end
end

% Indexing
for i = 1:8
    Load_increase(1,i) = load(1,i);
    Load_increase(2,i) = load(2,i);
    Load_increase(3,i) = load(3,i);
    Load_increase(4,i) = load(4,i);
    Load_increase(5,i) = load(5,i);
    Load_increase(6,i) = load(6,i);
    Load_increase(7,i) = load(7,i);
    Load_increase(8,i) = load(8,i);
    Load_increase(9,i) = load(9,i);
    Load_increase(10,i) = load(10,i);
    Load_increase(11,i) = load(11,i);
    Load_increase(12,i) = load(12,i);
    Load_increase(13,i) = load(13,i);
    Load_increase(14,i) = load(14,i);
    Load_increase(15,i) = load(15,i);
    Load_increase(16,i) = load(16,i);
```

```
    Load_increase(17,i) = load(17,i);
    Load_increase(18,i) = load(18,i) + load(19,i);
    Load_increase(19,i) = load(20,i);
    Load_increase(20,i) = load(21,i);
    Load_increase(21,i) = load(22,i);
    Load_increase(22,i) = load(23,i);
    Load_increase(23,i) = load(24,i);
    Load_increase(24,i) = load(25,i);
    Load_increase(25,i) = load(26,i);
    Load_increase(26,i) = load(27,i);
    Load_increase(27,i) = load(28,i);
    Load_increase(28,i) = load(29,i) + load(30,i);
    Load_increase(29,i) = load(31,i);
end

% Indexing for each bus with a generator/storage unit on it
load_bus_index = [1 2 3 4 8 9 11 17 23 45 55 56 59 61 62 63 64 83 90 103 ...
    106 117 132 140 141 149 153 186 187];

% Extracts bus data
Bus = xlsread(file_name,2,'F4:M209');

% Add "loss loads" to load already on bus
New_bus = Bus;
for i = 1:29
    for j = 1:8
        New_bus(load_bus_index(i),j) = New_bus(load_bus_index(i),j) ...
                                        + Load_increase(i,j);
    end
end

% Diaplay "check" and "Load_increase" to be sure the load was properly
% changed
check = New_bus - Bus;

% Write data to new data file
xlswrite(final_name,New_bus,2,'F4');
```

A.4 MATLab code: take generator, storage, and load data to create peak-shaving plots

```
% Arizona State University
% Name: William J Dixon
% Date: Fall 2014
% Topic: MS Thesis
% Purpose: Take Gen data and output data to be used in making peak shaving
%          graphs

loss_name = 'Case9_Loss_Data_PW.xlsx';
no_loss_name = 'Case9_Gen_Data_PW.xlsx';
loss_data = 'Case9_data.xlsx';
no_loss_data = 'Case9_losses_data.xlsx';
newfile = 'Case9_peak_shaving.xlsx';
```

```
% Read in Gen Data that came from PW
Gen_loss(:,1) = xlsread(loss_name,1,'E3:E33');
Gen_loss(:,2) = xlsread(loss_name,2,'E3:E33');
Gen_loss(:,3) = xlsread(loss_name,3,'E3:E33');
Gen_loss(:,4) = xlsread(loss_name,4,'E3:E33');
Gen_loss(:,5) = xlsread(loss_name,5,'E3:E33');
Gen_loss(:,6) = xlsread(loss_name,6,'E3:E33');
Gen_loss(:,7) = xlsread(loss_name,7,'E3:E33');
Gen_loss(:,8) = xlsread(loss_name,8,'E3:E33');

% Generator Bus Index
index_gens = [1 2 4 8 9 11 17 23 45 55 56 59 61 62 63 64 83 90 103 ...
    106 117 132 140 141 186 187];

% Storage Unit Bus Index
index_stor = [3 83 149 153 186];

Gen(:,1) = xlsread(no_loss_name,1,'E3:E33');
Gen(:,2) = xlsread(no_loss_name,2,'E3:E33');
Gen(:,3) = xlsread(no_loss_name,3,'E3:E33');
Gen(:,4) = xlsread(no_loss_name,4,'E3:E33');
Gen(:,5) = xlsread(no_loss_name,5,'E3:E33');
Gen(:,6) = xlsread(no_loss_name,6,'E3:E33');
Gen(:,7) = xlsread(no_loss_name,7,'E3:E33');
Gen(:,8) = xlsread(no_loss_name,8,'E3:E33');

gen_int_sum = zeros(1,size(Gen,2));
storage_int_sum = zeros(1,size(Gen,2));
loss_gen_int_sum = zeros(1,size(Gen_loss,2));
loss_storage_int_sum = zeros(1,size(Gen_loss,2));

for j = 1:size(Gen,2)
    for i = 1:size(Gen,1)
        if i~=3 && i~=19 && i~= 27 && i~=28 && i~= 30
        gen_int_sum(j) = gen_int_sum(j) + Gen(i,j);
        else
        storage_int_sum(j) = storage_int_sum(j) + Gen(i,j);
        end
    end
    for i = 1:size(Gen_loss,1)
        if i~=3 && i~=19 && i~= 27 && i~=28 && i~= 30
        loss_gen_int_sum(j) = loss_gen_int_sum(j) + Gen_loss(i,j);
        else
        loss_storage_int_sum(j) = loss_storage_int_sum(j) + Gen_loss(i,j);
        end
    end
end

total_power = gen_int_sum - storage_int_sum
Load = xlsread(no_loss_data,2,'F210:M210')


loss_total_power = loss_gen_int_sum - loss_storage_int_sum
Load_losses = xlsread(loss_data,2,'F210:M210')
```

```
xlswrite(newfile,total_power,1,'A1');
xlswrite(newfile,Load,1,'A2');
xlswrite(newfile,loss_total_power,1,'A3');
xlswrite(newfile,Load_losses,1,'A4');
```

APPENDIX B

CASE SPECIFIC PEAK-SHAVING DATA

B.1 Peak-shaving data

Since it is difficult to visually determine the differences of each case peak-shaving graph, all the peak-shaving graphs have been provided in this Appendix rather than in the chapters. Table 3.4, which describes the case numbering system, is provided here for convenience.

Table 3.4 Case numbering system

Case numbering system				
Generator Cost Change	**Base case (No Storage)**	**E/P Ratio 1**	**E/P Ratio 5**	**E/P Ratio 10**
10%	0''	3	6	9
0%	0	1	4	7
-10%	0'	2	5	8

*0” and 0’ refer to the base case with generator costs varied by ±10% respectively

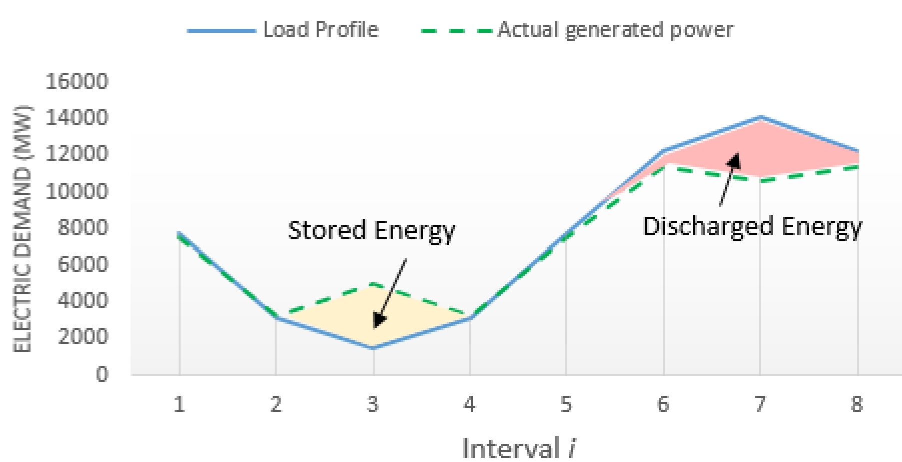

Figure B.1: Case 1 – Lossless Peak-Shaving

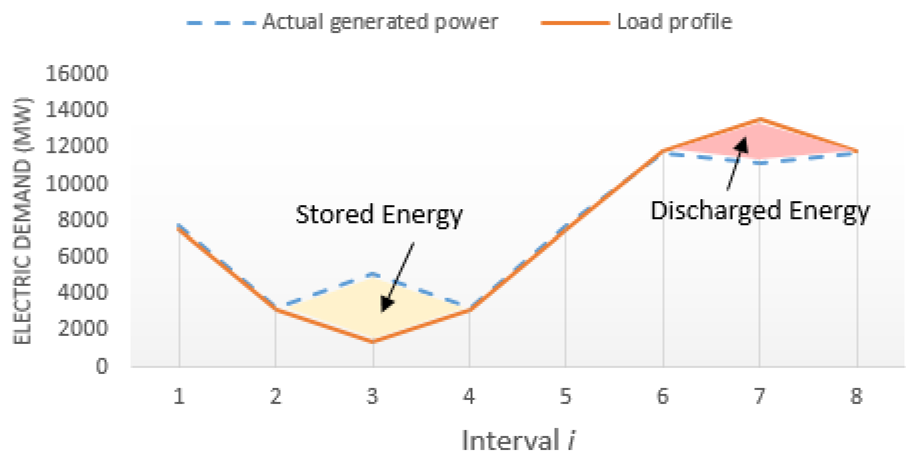

Figure B.2: Case 1 – Losses Included Peak-Shaving

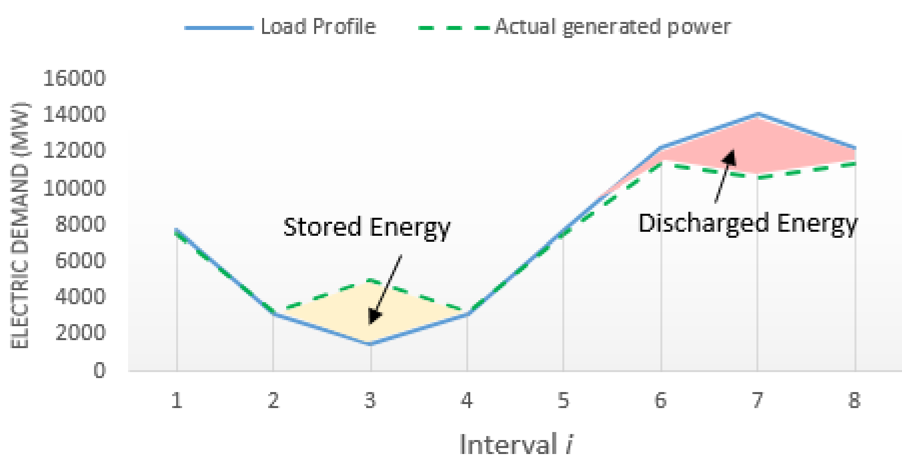

Figure B.3: Case 2 – Lossless Peak-Shaving

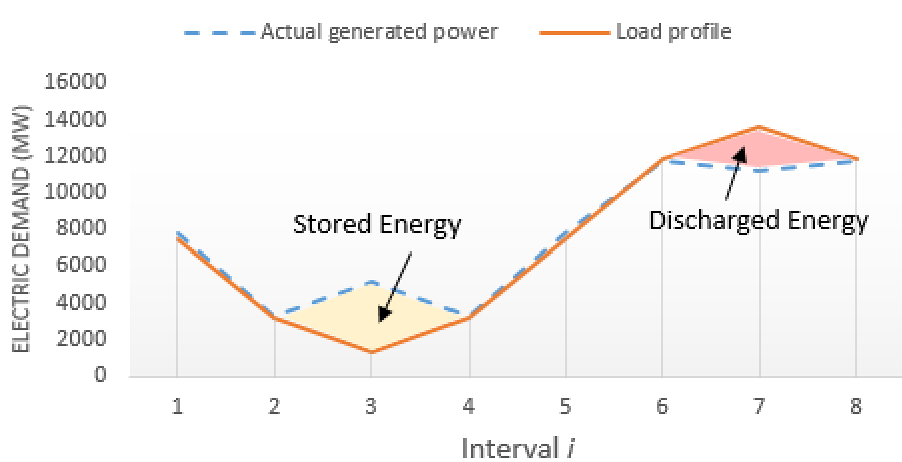

Figure B.4: Case 2 – Losses Included Peak-Shaving

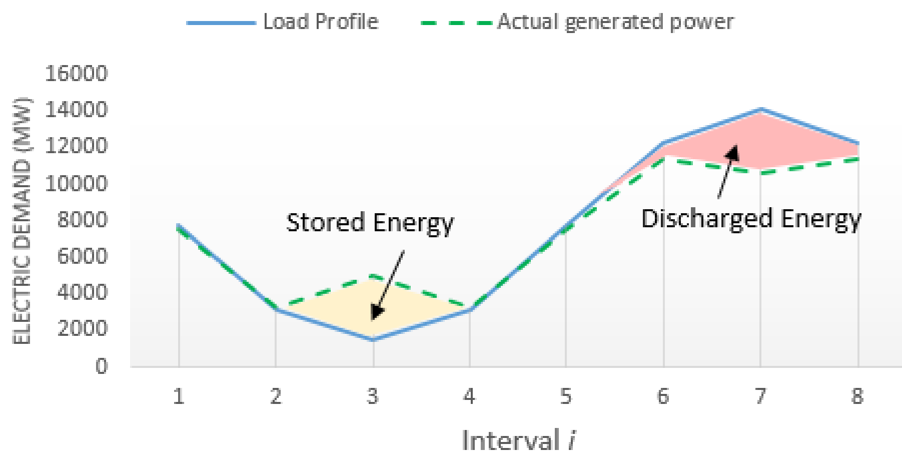

Figure B.5: Case 3 – Lossless Peak-Shaving

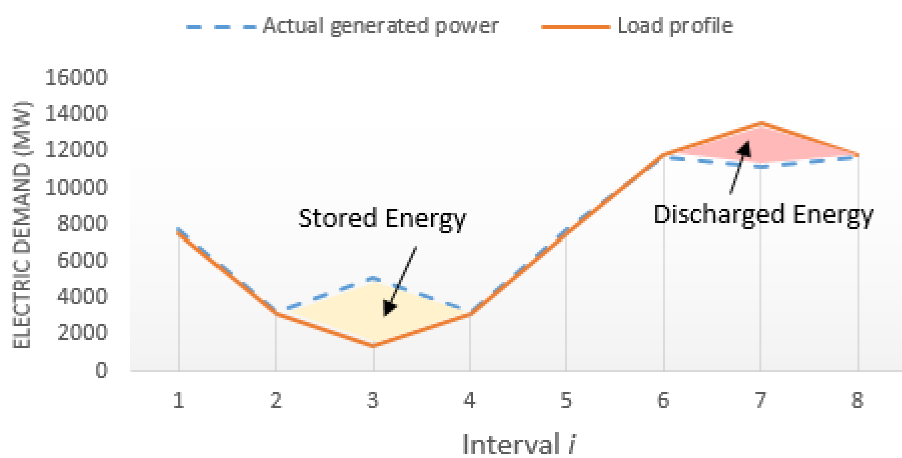

Figure B.6: Case 3 – Losses Included Peak-Shaving

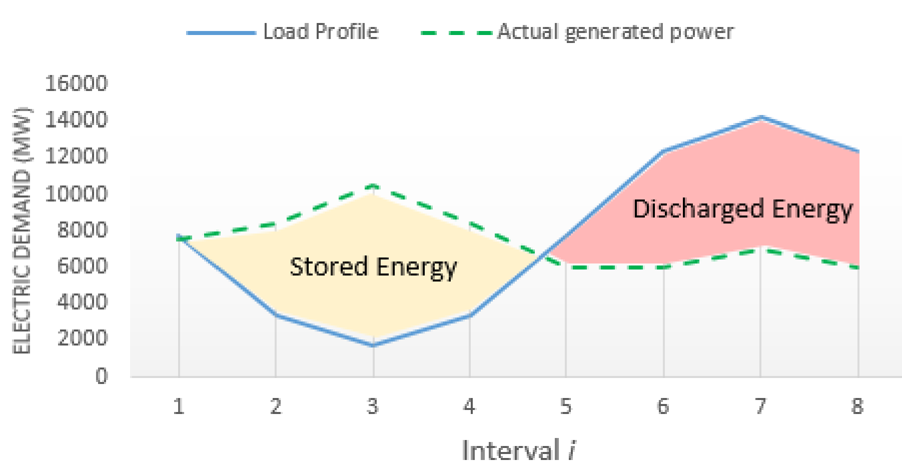

Figure B.7: Case 4 – Lossless Peak-Shaving

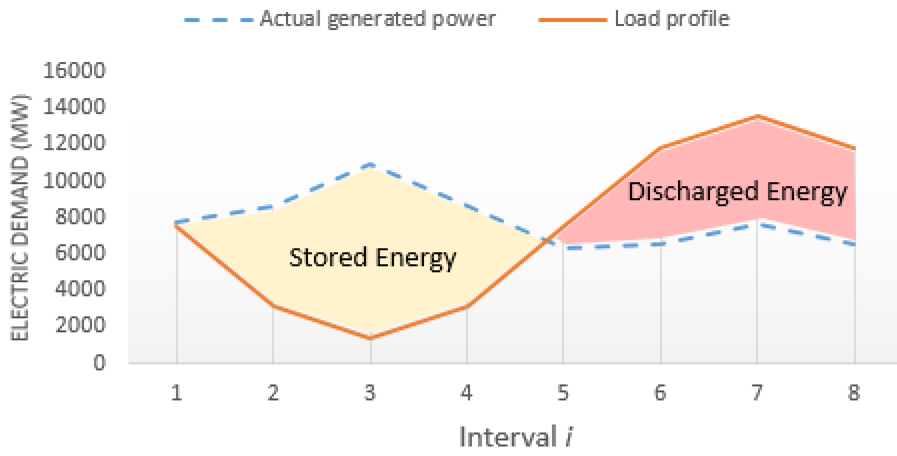

Figure B.8: Case 4 – Losses Included Peak-Shaving

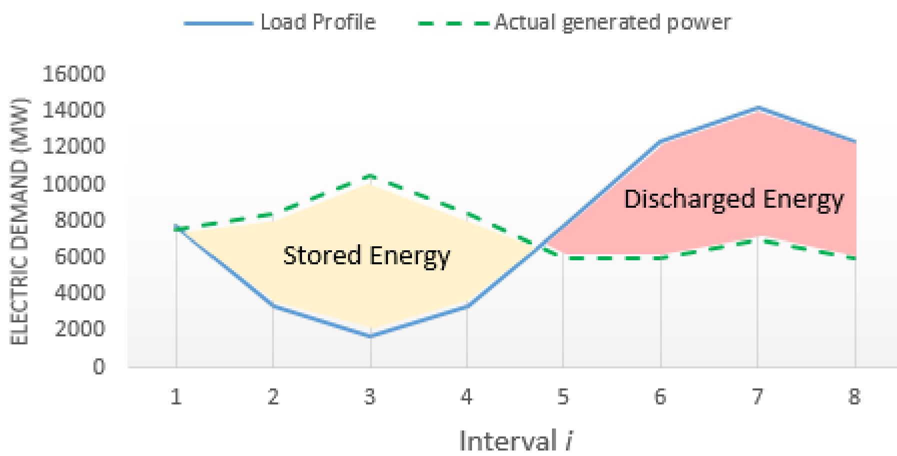

Figure B.9: Case 5 – Lossless Peak-Shaving

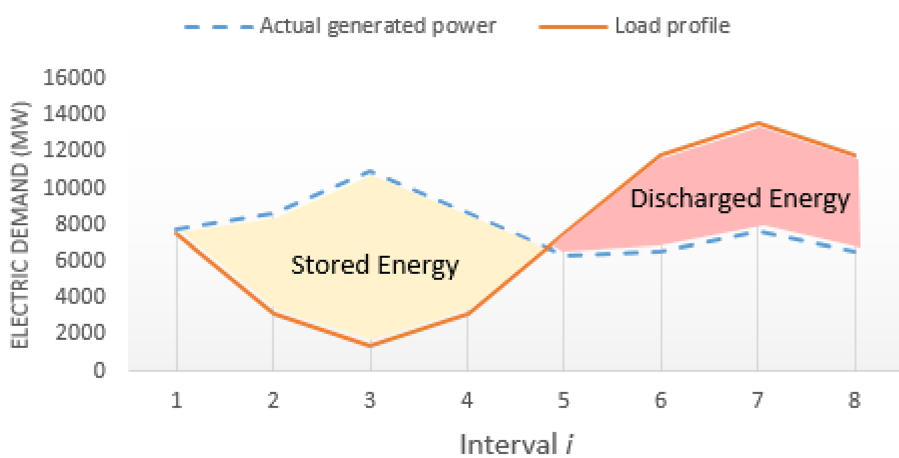

Figure B.10: Case 5 – Losses Included Peak-Shaving

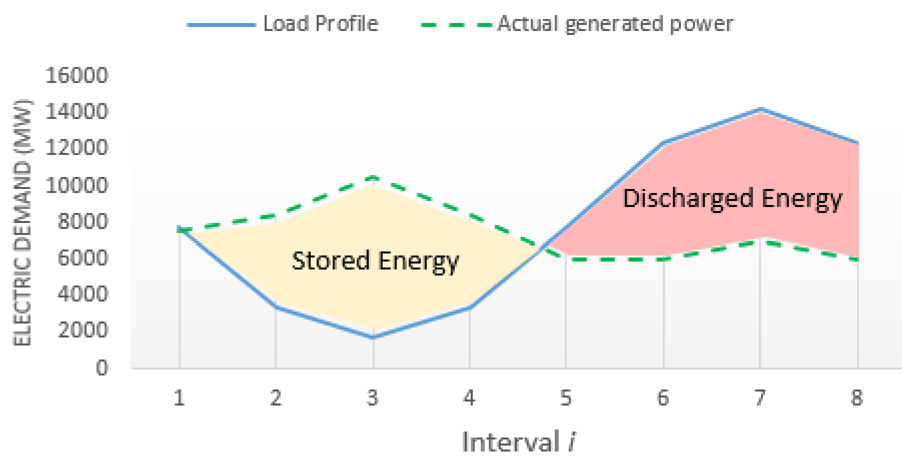

Figure B.11: Case 6 – Lossless Peak-Shaving

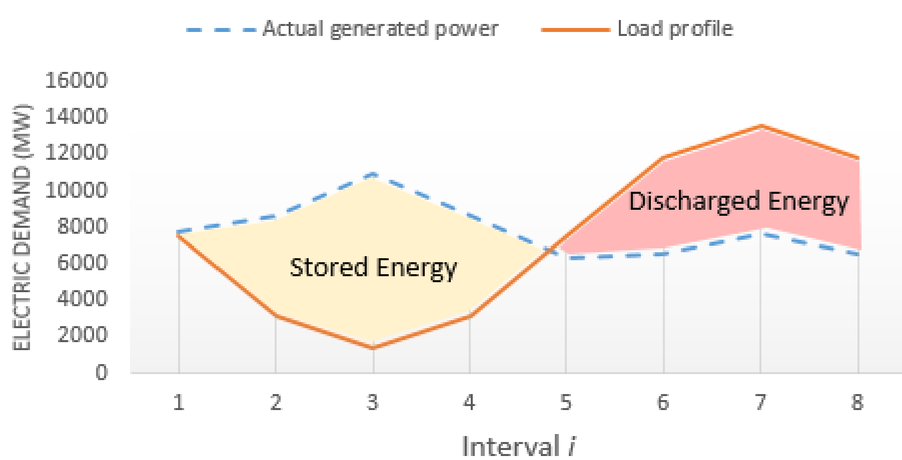

Figure B.12: Case 6 – Losses Included Peak-Shaving

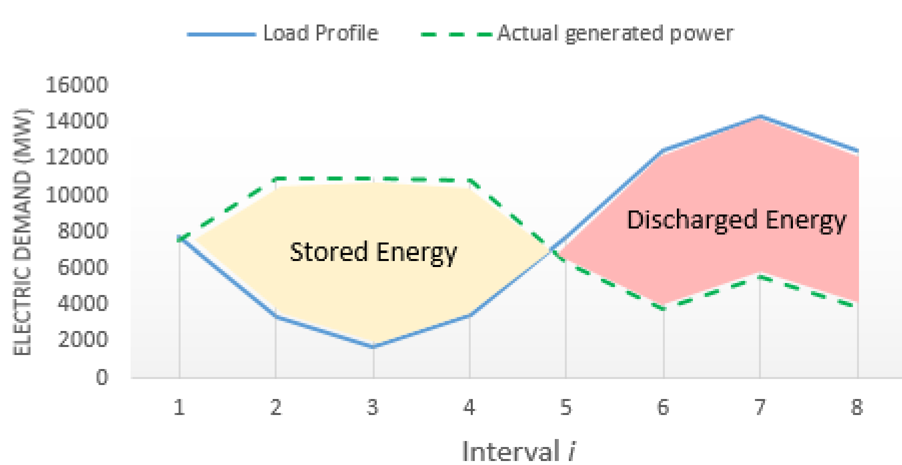

Figure B.13: Case 7 – Lossless Peak-Shaving

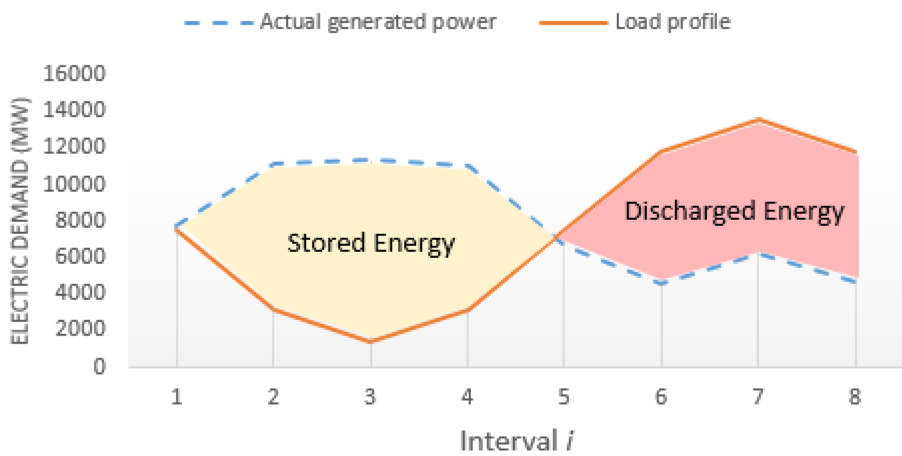

Figure B.14: Case 7 – Losses Included Peak-Shaving

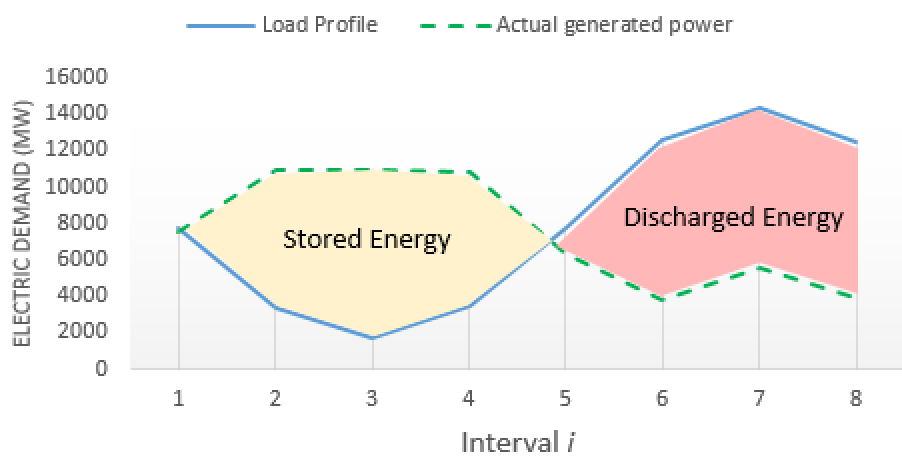

Figure B.15: Case 8 – Lossless Peak-Shaving

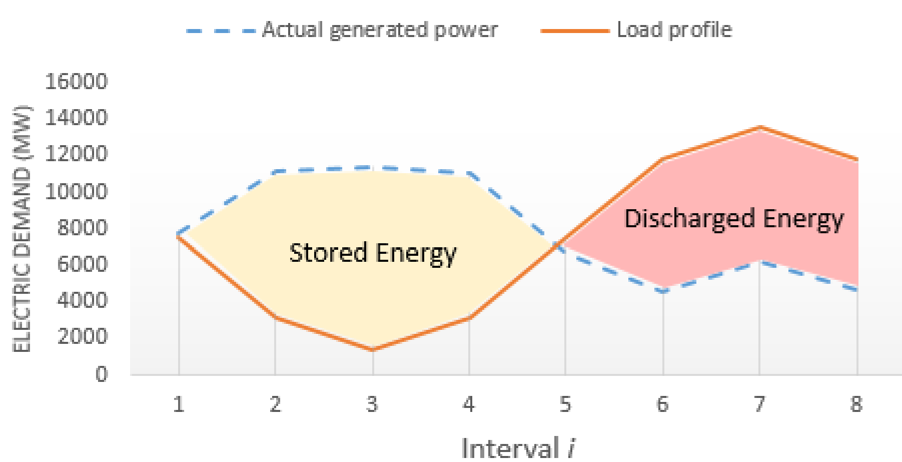

Figure B.16: Case 8 – Losses Included Peak-Shaving

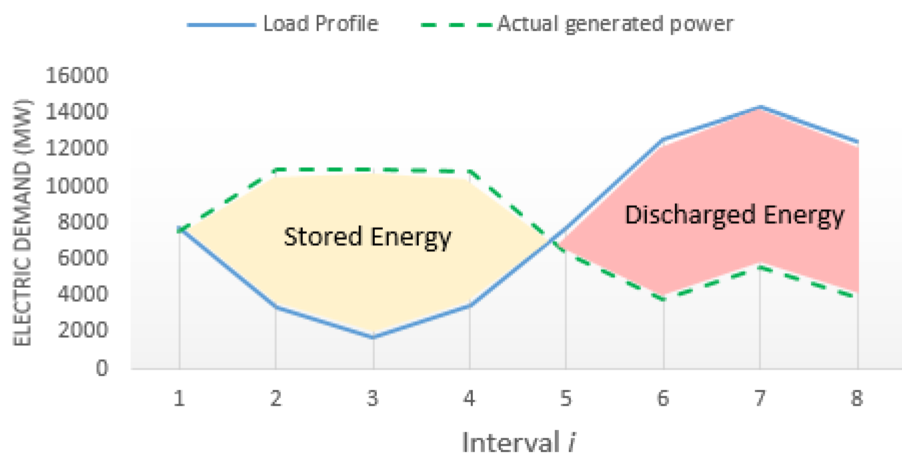

Figure B.17: Case 9 – Lossless Peak-Shaving

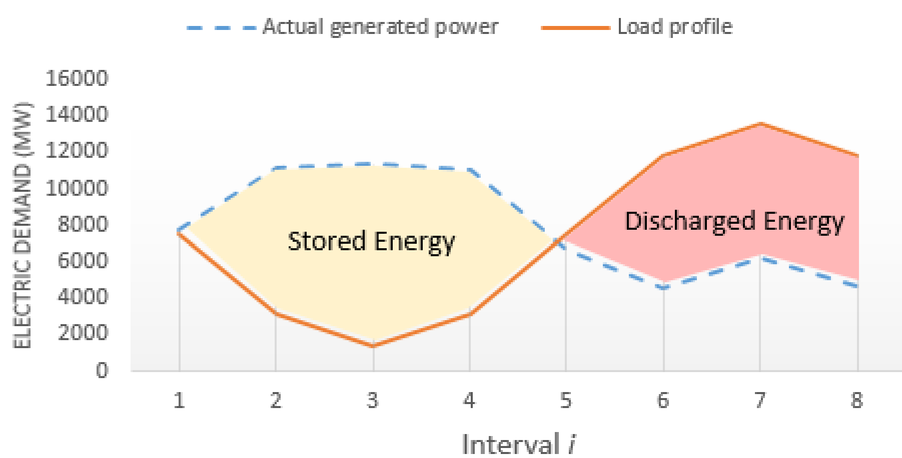

Figure B.18: Case 9 – Losses Included Peak-Shaving

APPENDIX C

GUROBI OPTIMIZER

C.1 Gurobi optimizer

Gurobi was the higher level language chosen to solve the formulized quadratic program. From within the MATLab environment, an optimization model may be built and passed to Gurobi to obtain the optimization result. MATLab was chosen at the programming environment because of its robustness with large data sets (sparse functions) and matrix-oriented interface. Gurobi-MATLab can be used to solve LP, QP, QCP, MIP, MILP, or MIQP.

The Gurobi-MATLab interface is used to solve optimization problems as shown in (C.1) with the constraints (‘*subject to*’) shown in (C.2-C.7) [33].

$$minimize: x^T Q x + \ c^T + \alpha \tag{C.1}$$

$$Ax = b \text{ (linear constraints)} \tag{C.2}$$

$$l \leq x \leq u \text{ (bound constraints)} \tag{C.3}$$

$$\text{some } x_j \text{ integral (integrality constraints)} \tag{C.4}$$

$$\text{some } x_k \text{ lie within second order cones (cone constraints)} \tag{C.5}$$

$$x^T Q_c x + q^T x \leq \beta \text{ (quadratic constraints)} \tag{C.6}$$

$$\text{some } x_i \text{ in SOS (special ordered set constraints)} \tag{C.7}$$

Most of the model components listed in equations (C.2-C.7) are optional. For the purposes of this thesis, the integrality, cone, quadratic (see Section 2.5), and special ordered constraints are not used. The Gurobi-MATLab interface has restrictions for the model structure, these are listed in Table C.1. Please note, these are parameters set in MATLab to pass to Gurobi. The information in Table C.1 is taken *directly* from the Gurobi user manual [34].

Observe that a few of the parameters listed in Table C.1 are not used for this thesis, but are provided in the table to demonstrate the functionality of Gurobi. The *quadcon* parameter may be used to implement the quadratic constraints (for adding transmission line losses) as discussed in

Section 2.5. The parameter *vtype* may be used to add binary variables to the linear constraint matrix *A*. This would be especially useful for adding a generator status constraint (online or offline).

Table C.1 Gurobi-MATLab Interface Argument Descriptions [34]

Gurobi-MATLab model arguments	
model.A	The linear constraint matrix. This must be a sparse matrix.
model.obj	The linear objective vector (*c* in the above problem statement). You must specify one value for each column of *A*. This must be a dense vector.
model.sense	The sense of the linear constraints. Allowed values are '<', '=', '>'. You must specify one value for each row of A, or a single value to specify that all constraints have the same sense. This must be a character array.
model.rhs	The right-hand side vector for the linear constraints (*b* in the above problem statement). You must speficy one value for each for of *A*. This must be a dense vector.
model.lb (optional)	The lower bounds on the variables. When present, you must specify one value for each column of A. This must be a dense vector. When absent, each variable has a lower bound of 0.
model.up (optional)	The upper bounds on the variables. When present, you must specify one value for each column of A. This must be a dense vector. When absent, the variables have infinite upper bounds.
model.vtype (optional)	The variable types. This char array is used to capture variable integrality constraints. Allowed values are 'C' (continuous), 'B' (binary), 'I' (integer), 'S' (semi-continuous), or 'N' (semi-integer). When present, you must specify one value for each column of A, or a single value to specify that all variables should have the same type. When absent, each variable is treated as being continuous.
model.modelsense (optional)	The optimization sense. Allowed values are 'min' (minimize) or 'max' (maximize). When absent, the default model sense is minimization.
model.objcon (optional)	The constant offset in the objective function (alpha in the above problem statement).
model.Q (optional)	The quadratic objective matrix. When present, Q must be a square matrix whose row and column counts are equal to the number of columns of A. Q must be a sparse matrix.
model.quadcon (optional)	The quadratic constraints. A struct array. The Qc matrix must be a square matrix whose row and column counts are equal to the number of columns of *A*. *Qc* must be a sparse matrix. The *q* vector defines the linear terms in the constraint. You must specify a value for q for each column of *A*. This must be a dense vector. It is stored in model.quadcon.q. The scalar beta defines the right-hand side of the constraint. It is stored in model.quadcon.rhs.