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Operations Optimization of Nuclear Hybrid Energy Systems

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Abstract — *Nuclear hybrid energy systems (NHESs) have been proposed as an effective element to incorporate high penetration of clean energy (e.g., nuclear and renewable). This paper focuses on the operations optimization of two specific NHES configurations to address the variability raised from wholesale electricity markets and renewable generation. Both analytical and numerical approaches are used to obtain the optimal operations schedule. Key economic figures of merit are evaluated under optimized and constant (i.e., time-invariant) operations to demonstrate the benefit of the optimization, which also suggests the economic viability of the considered NHESs under the proposed operations optimizer. Furthermore, sensitivity analysis on commodity prices is conducted for better understanding of the considered NHESs.*

Keywords — *Nuclear hybrid energy systems, renewable generation integration, operations optimization*.

Note — *Some figures may be in color only in the electronic version.*

I. INTRODUCTION

Nuclear hybrid energy systems (NHESs), which typically consist of multiple energy inputs (e.g., nuclear and renewable generation) and multiple energy outputs (e.g., electricity, gasoline, and freshwater) using complementary energy conversion processes, have been proposed to be an effective element to efficiently incorporate high penetration of clean energy generation.[1–13] By enabling more than one energy conversion unit, NHESs provide additional opportunities for flexible energy management, for delivering various types of ancillary services such as operating reserves (e.g., regulating, ramping, load-following, and supplemental reserves), and for enabling operational flexibility for value (technical and/or economic) optimization. Prior work on modeling, simulation, control, and dynamic property characterization of NHESs suggested that NHESs can be operated under flexible operations to accommodate the variability introduced from renewable generation and modern loads.[5–8] The objective of this paper is then to address the variability raised from market dynamics by proposing an operations optimizer that computes the optimal schedules among NHES components to maximize economic values, based on renewable generation and various market information including operations and maintenance (O&M) costs, feedstock costs, and real-time commodity pricing.

Optimization on hybrid energy systems (HESs) has been investigated in the literature,[4,10–13] for optimal system design or operational control to achieve maximize technical and/or economic values. For example, Ref. 4 considers an optimization problem for the design of HESs, where the sizes of two key components are computed for optimal production while maintaining minimal variability of process variables. References 12 and 13 focus on an optimization problem for hybrid renewable energy generation systems that excludes any consumption component.

Different from the above-mentioned work, this paper is focused on operations optimization of NHESs consisting of not only various generation units but also multiple energy conversion loads. Specifically, two regional NHES configurations—NHES_Texas and NHES_Arizona—are considered in this paper. These two regional NHES configurations have been closely examined in the authors' prior work[5–8] for their dynamic technical performance and have been shown to be technically viable for flexible operations and participation in volatile markets. The first

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configuration, NHES_Texas, employs a nuclear plant and a series of wind turbines for energy generation, produces electricity, and converts carbon resources to gasoline using excess thermal capacity. The second configuration, NHES_Arizona, uses a nuclear plant and solar photovoltaic (PV) stations for energy generation and yields electricity to meet grid demand as well as to produce freshwater. Operations optimization problems are formulated for these two regional NHES configurations, which are solved by both analytical and numerical approaches, for maximizing key economic figures of merit (FOMs). The economic advantages of such an operations optimizer and associated flexible operations are illustrated by comparing the economic FOMs resulting from optimized operations versus the ones resulting from constant (i.e., time-invariant) operations. Sensitivity analysis on price changes is also performed.

The rest of this paper is organized as follows. Section II reviews the topological architectures of the considered NHES configurations. Economic functions and operations optimization problems for two specific NHES configurations are formulated in Sec. III, where the main results on the optimization solution are also presented. Section IV includes numerical results, and the paper concludes in Sec. V with discussions for future efforts. Additional economic functions are included in the Appendixes.

II. NHES CONFIGURATIONS AND OPERATIONS

The network topologies of the considered NHES configurations—NHES_Texas and NHES_Arizona—are shown in Figs. 1 and 2, respectively, which include

1. a heat generation plant with 180-MW capacity,[a] consisting of a small modular reactor (SMR) and a steam generator, denoted as primary heat generation (PHG)
2. series of steam turbines, feedwater systems, and heaters, paired with an electric generator that converts steam into electricity, denoted as thermal-to-electrical conversion (TEC)

[a]For simplicity, all power calculations will be expressed using the electrical equivalence (in megawatts) of the particular power stream, assuming fixed TEC efficiency.

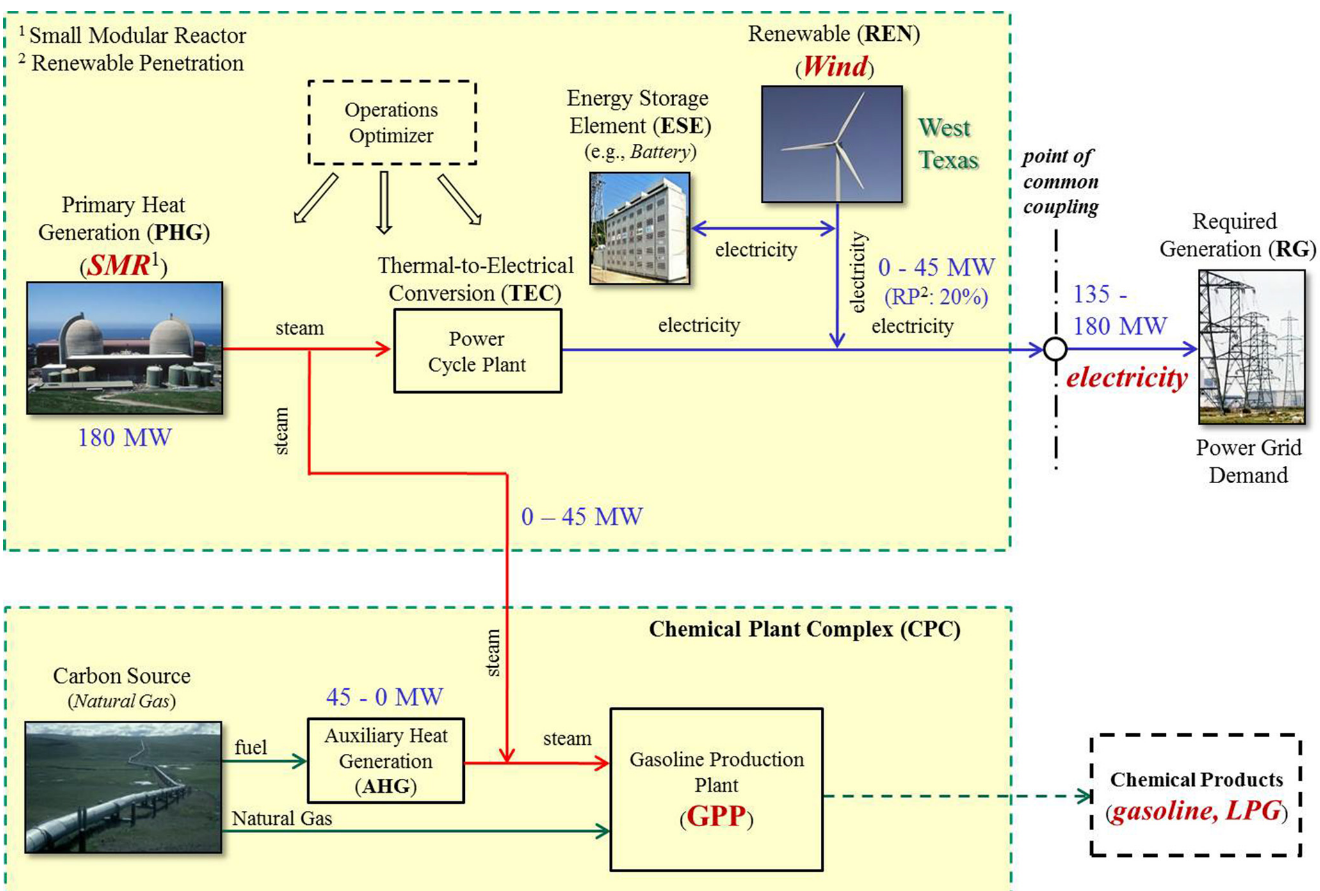

Fig. 1. Network topology of NHES_Texas with a flexible thermal load.

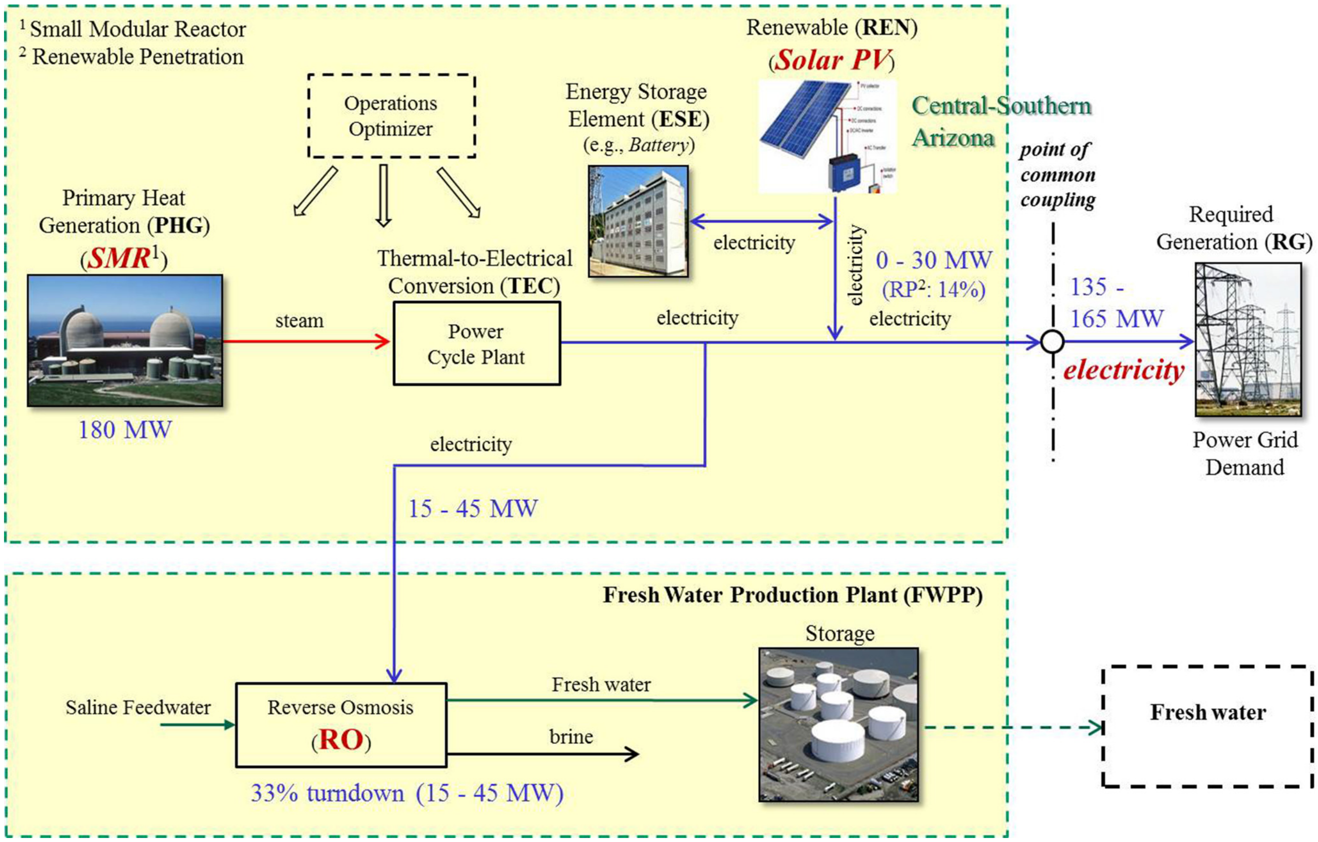

Fig. 2. Network topology of NHES_Arizona with a flexible electrical load.

3. a renewable power generation source, denoted as REN (renewable), consisting of, respectively,

   a. NHES_Texas: a series of wind turbines with total capability of 45 MW

   b. NHES_Arizona: a PV solar station with nominal capability of 30 MW

4. electrical storage (i.e., a system scale battery set) used for power smoothing of the electricity generated by REN, denoted energy storage element (ESE)

5. additional energy conversion units, consisting of, respectively,

   a. NHES_Texas: a chemical plant complex including a gasoline production plant (GPP) and an auxiliary heat generation (AHG), where GPP is able to utilize process steam up to 45 MW and convert natural gas (NG) and water into gasoline [and liquefied petroleum gas (LPG)]. AHG is a NG-fired steam generator boiler plant of up to 45-MW capacity that generates additional on-demand steam.

   b. NHES_Arizona: a reverse osmosis (RO) desalination plant (RODP) able to utilize electricity up to 45 MW to convert saline or brackish water into freshwater and brine. This RODP has a minimum turndown of 33%.

6. electric grid connected to NHES at a point of common coupling and consuming electricity up to 180 MW in NHES_Texas or 165 MW in NHES_Arizona, respectively

7. an operations optimizer that computes operations schedule and energy distribution among HES components, according to various market dynamics and renewable generations, for maximal economic performance.

There are two units for electricity generation in each of the above two NHES configurations, namely, TEC and REN, which are operated accordingly to deliver the electricity generation requested by the operations optimizer. Electricity is the first output of NHES. The second output is gasoline in NHES_Texas or freshwater in NHES_Arizona, produced by using excess energy in forms of process steam or electricity. Note that PHG is sized for full-load operation (i.e., 180 MW); therefore, it is capable of generating (without renewable contribution) sufficient process steam to meet the maximum electric grid demand.

For NHES_Texas, when the process steam from PHG is not sufficient for GPP, AHG would generate on-demand steam to maintain a constant production rate at GPP. Hence, GPP is operated in full-load mode, regardless of the renewable contribution and grid demand. Under the extreme situation that the requested electricity generation is 180 MW and no renewable contribution is present, minimal process steam is directed to GPP, with the steam duty being met by AHG. In the event of a nonzero renewable contribution, the amount of electricity generated by the power cycle is determined by an operations optimizer based on the renewable contribution, and the remaining thermal energy produced by PHG operating at full load is sent to GPP in the form of heated steam via a secondary boiler.

For NHES_Arizona, the electricity available for RODP depends on the renewable contribution and grid demand, varying between 15 and 45 MW. Under the extreme situation that a constant electricity generation of 165 MW is requested in the absence of a renewable contribution, the electrical power provided to RODP is just 15 MW. In the event of a nonzero renewable contribution, RODP may be then operated beyond the minimum of 15 MW under the guidance of the operations optimizer.

For additional detail on the considered NHESs, refer to Refs. 5 through 8.

III. ECONOMIC FUNCTIONS AND OPERATIONS OPTIMIZATION

III.A. Economic FOM

The economic FOMs considered here are those typically relevant for economic analysis of energy systems, namely, net present value (NPV), payback period, and internal rate of return (IRR). NPV is defined as follows[14]:

$$\mathrm{NPV} = \sum_{k=0}^{N} \frac{\mathrm{FCFF}_{R,k}}{(1 + r_R)^k} , \tag{1}$$

where

N = year of operations of NHES plant

r_R = discount rate (assumed to be 5%) used in computing weighted average cost of capital (WACC)

$\mathrm{FCFF}_{R,k}$ = real discounted free cash flow to firm (FCFF) for year k, defined as

$$\mathrm{FCFF}_{R,k} = (R_k - C_{\mathrm{O\&M},k} - DA_k(1 + i)^{-k})(1 - \sigma) + DA_k(1 + i)^{-k} - C_{ghg,k} - CAPEX_k , \tag{2}$$

where

σ = tax rate

i = inflation rate (assumed to be 3%)

and $CAPEX_k$ (capital expense) only occurs when $k = 0$, i.e., year 0, given by

$$CAPEX_0 = C_{cap} ,$$

and $CAPEX_k = 0$ for all $k > 0$. The capital cost C_{cap}, O&M cost $C_{\mathrm{O\&M},k}$, cost for greenhouse gas (GHG) emission $C_{ghg,k}$, and revenue R_k, for year k, will be defined shortly for each of the NHES configurations. Depreciation and amortization DA for year k for tax deduction under modified accelerated cost recovery systems, i.e., DA_k in Eq. (2), is calculated by

$$DA_k = \rho_{da,k} C_{cap} ,$$

where $\rho_{da,k}$ is the depreciation and amortization rates[b] at year k.

Payback period, or payback time, is defined as the years of operations such that NPV equals 0 (Ref. 16). Finally, for a fixed N years of operations, the IRR is defined as the value of the discount rate r_R such that NPV equals 0 (Ref. 17).

III.B. Operations Optimization for NHES_Texas

For NHES_Texas, R_k consists of the revenue from sales of electricity and gasoline for year k and is given by

$$R_k = \int_0^T P_e \beta_e + M_g \beta_g dt ,$$

where

T = considered time period (e.g., 1 year)

P_e = electrical power sold to the electric grid[c]

β_e = price of electricity

M_g = gasoline (plus LPG) production rate, which is constant at 45.3 kg/s (as GPP is operated at constant mode)

β_g = gasoline (and LPG) price.

The cost for GHG emission is given by

[b] $\rho_{da,k}$ for $k \leq 16$, i.e., the first 16 years, are 5.00%, 9.50% , 8.55%, 7.70%, 6.93%, 6.23%, 5.90%, 5.90%, 5.91%, 5.90%, 5.91%, 5.90%, 5.91%, 5.90%, 5.91%, 2.95%, respectively, and 0% afterward.[15]

[c] Without causing any confusion, all the variables that are functions of time t are denoted without subscript or superscript t.

$$C_{ghg,k} = \int_0^T M_c \beta_c dt ,$$

where

M_c = emission rate of GHG (CO_2 in this case)

β_c = cost per unit of GHG emission.

The capital cost C_{cap} and O&M cost $C_{\mathrm{O\&M},k}$ are divided according to five major components, i.e., PHG (including power cycle), AHG, REN, ESE, and GPP, and are given by

$$C_{cap} = C_{phg} + C_{ahg} + C_{ren} + C_{ese} + C_{gpp}$$

and

$$C_{\mathrm{O\&M},k} = \mathrm{O\&M}_{phg} + \mathrm{O\&M}_{ahg} + \mathrm{O\&M}_{ren} + \mathrm{O\&M}_{ese} + \mathrm{O\&M}_{gpp} .$$

The computations of capital and O&M cost for the five major components are given in Appendix A.

It is not difficult to see that maximizing the NPV defined in Eq. (1), minimizing the payback period, and maximizing the IRR are all equivalent to maximizing the $\mathrm{FCFF}_{R,k}$ defined in Eq. (2) for each year k. By dropping from Eq. (2) the terms that are constant with respect to operations, which include $CAPEX_k$ and terms related to DA_k, the objective function for operations optimization is thus given by

$$J_{tx} = (R_k - C_{\mathrm{O\&M},k})(1 - \sigma) - C_{ghg,k} . \quad (3)$$

The constraints over the variables for all time t are as follows:

$$P_e - P_w + P_T = P_{phg} , \quad (4)$$

$$0\mathrm{MW} \leq P_e \leq P_{phg} , \quad (5)$$

and

$$0\mathrm{MW} \leq P_T \leq P_g , \quad (6)$$

where

P_w = electrical power generated by wind turbines

P_T = power generated by PHG and consumed by GPP

P_{phg} = power generated by PHG, which is 180 MW constant

P_g = rated maximum power consumption of GPP.

Note that Eq. (4) essentially represents the energy balance within the NHES components. Combining constraints (4), (5), and (6) gives $\max(0\mathrm{MW}, P_{phg} + P_w - P_g) \leq P_e \leq \min(P_{phg}, P_{phg} + P_w)$ or, equivalently,

$$P_{phg} + P_w - P_g \leq P_e \leq P_{phg} . \quad (7)$$

Note that the above relationship requires that $P_{phg} + P_w - P_g \geq 0\mathrm{MW}$ (equivalently $P_{phg} \geq P_g$) and $P_{phg} + P_w \geq P_{phg}$ (equivalently $P_w \geq 0\mathrm{MW}$), both of which are true in NHES_Texas. Finally, in order to characterize the relationships among decision variables (i.e., P_e, M_{ahg_NG}, and M_c), the following linear relationships are assumed for all time instances[d]:

$$M_{ahg\_\mathrm{NG}} = k_0 + k_1(P_e - P_w) \quad (8)$$

and

$$M_c = \gamma M_{ahg\_\mathrm{NG}} . \quad (9)$$

In summary, the operations optimization problem is formulated as follows:

Maximize J_{tx} as in Eq. (3),
subject to Eqs. (7), (8), and (9).

To solve the above optimization problem, the derivative of objective function (3) is taken with respect to P_e, and relationships (8) and (9) are substituted, yielding

$$\frac{dJ_{tx}}{dP_e} = \int_0^T (1 - \sigma)(\beta_e - k_1\beta_{\mathrm{NG}}) - \gamma k_1 \beta_c dt . \quad (10)$$

Therefore, the analytical solution is as follows:

At each time instance t,

$$P_e = \begin{cases} P_{phg} & \text{if } (1-\sigma)(\beta_e - k_1\beta_{NG}) - \gamma k_1 \beta_c > 0 \\ P_{phg} + P_w - P_g & \text{otherwise.} \end{cases} \quad (11)$$

Remark 1: The above optimization solution does not depend on the market price of gasoline. This is because regardless of its market price, GPP is operated at constant mode, producing gasoline at its maximum rate. However, because of the variation of electricity price, the amount of electricity sold to the electric grid varies to maximize profit. In this case, the amount of NG used to keep GPP at full-load mode is changing accordingly, and hence, the price of NG needs to be considered in the optimization.

[d]The values for k_0 and k_1 in Eq. (8) are determined by simulations of NHES_Texas modeling in Modelica and are given as $k_0 = -8.07$ and $k_1 = 7.63\mathrm{E}{-2}$.

III.C. Operations Optimization for NHES_Arizona

For NHES_Arizona, R_k consists of the revenue from sales of electricity and freshwater for year k and is given by

$$R_k = \int_0^T P_e\beta_e + M_{fw}\beta_{fw}dt ,$$

where

M_{fw} = production rate of freshwater by RODP

β_{fw} = price of freshwater.

The cost for GHG emission is 0 for NHES_Arizona as there is no GHG emission in this case. The capital cost C_{cap} and O&M cost $C_{O\&M,k}$ are divided into four major components, i.e., PHG (including power cycle), REN, ESE, and RODP, and are given by

$$C_{cap} = C_{phg} + C_{ren} + C_{ese} + C_{rodp}$$

and

$$C_{O\&M,k} = O\&M_{phg} + O\&M_{ren} + O\&M_{ese} + O\&M_{rodp} .$$

The computations of capital and O&M cost for the four major components are given in Appendix B.

Similar to the case of NHES_Texas, by dropping from Eq. (2) the terms that are constant with respect to operations, the objective function for operations optimization is thus given by

$$J_{az} = (1 - \sigma)\int_0^T P_e\beta_e + M_{fw}\beta_{fw} - \beta_{v\_rodp}M_{fw}dt . \tag{12}$$

The constraints over the variables for all time t are as follows:

$$P_e - P_s + P_{RO} = P_{phg} , \tag{13}$$

$$0\text{MW} \leq P_e \leq P_{phg} - P_{ROL} , \tag{14}$$

and

$$P_{ROL} \leq P_{RO} \leq P_{ROU} , \tag{15}$$

where

P_s = electrical power generated by PV solar station

P_{RO} = electrical power consumed by RODP

P_{ROL}, P_{ROU} = lower and upper limits, respectively, of the power consumed by RODP.

Note that Eq. (13) essentially represents the energy balance within the NHES components. Combining constraints (13), (14), and (15) gives $\max(0\text{MW}, P_{phg} + P_s - P_{ROU}) \leq P_e \leq \min(P_{phg} - P_{ROL}, P_{phg} + P_s - P_{ROL})$ or, equivalently,

$$P_{phg} + P_s - P_{ROU} \leq P_e \leq P_{phg} - P_{ROL} . \tag{16}$$

Note that the above relationship requires that $P_{phg} + P_s - P_{ROU} \geq 0\text{MW}$ (equivalently $P_{phg} \geq P_{ROU}$) and $P_{phg} + P_s - P_{ROL} \geq P_{phg} - P_{ROL}$ (equivalently $P_s \geq 0\text{MW}$), both of which are true in NHES_Arizona. Finally, in order to characterize the relationship between the power consumed by RODP and its freshwater production, the following nonlinear relationship is assumed[e]:

$$M_{fw} = k_0 + k_1P_{RO} + k_2P_{RO}^2 . \tag{17}$$

In summary, the operations optimization problem is formulated as follows:

Maximize J_{az} as in Eq. (1),
subject to Eqs. (13), (16), and (17).

Remark 2: The above optimization problem is numerically solved by an implementation of the interior-point method[18] that aims at solving linear and nonlinear convex optimization problems. The interior-point method introduced in Ref. 18 constructs a dual problem (called barrier problem) of the original optimization problem and applies the sequential quadratic programming techniques for obtaining the optimal primary and dual variables.

IV. RESULTS

This section presents the numerical results of the operations optimization. The optimized electrical power sold to the electric grid P_e, together with renewable generation profiles taken from Refs. 5 and 6, are fed into the NHES model implemented in Modelica for simulation, which provides all process variables necessary to compute the economic FOM.

IV.A. Optimization Results for NHES_Texas

Table I lists all the parameter values for simulation of NHES_Texas with their sources listed in Table III as well,

[e]The values for k_0, k_1, and k_2 in Eq. (17) are determined by simulations of NHES_Arizona modeling in Modelica and are given as $k_0 = 301.77$, $k_1 = 442.20$, and $k_3 = -2.16$.

TABLE I

Parameter Values Used for NHES_Texas

	Parameter	Value	Source
Nuclear and power cycle	Unit capital cost, α_{phg} (\$ · kW $^{-1}$) Fixed O&M cost coefficient, β_{f_phg} (\$ · MW · h^{-1}) Maximum power output, P_{phg_r} (kW)	4718 27.91 180000	Refs. 20 and 21 Ref. 22 Ref. 6
Wind farms	Unit capital cost, α_{ren} (\$ · kW^{-1}) Fixed O&M cost coefficient, β_{f_ren} (\$ · kW^{-1}) Maximum power output, P_{ren_r} (kW)	2339.61 36.91 45000	Ref. 23 Ref. 23 Ref. 6
Storage	Unit capital cost, α_{ese} (\$ · kW · h^{-1}) Fixed O&M cost coefficient, β_{f_ese} (%) Maximum storage capacity, $\lvert E_{ese}\rvert$ (kW · h)	81.42 3 16000	Ref. 2 Ref. 2 Ref. 6
AHG	Unit capital cost, α_{ahg} (\$ · kW^{-1}) Fixed O&M cost coefficient, β_{f_ahg} (%) Maximum power output, P_{ahg_r} (kW)	1057.44 3 45000	Ref. 24 Ref. 24 Ref. 6
GPP	Unit capital cost, α_{gpp} (\$ · kg^{-1} · s) Fixed O&M cost coefficient, β_{f_gpp} (%) Water price, β_w (\$ · kg^{-1}) Maximum production rate, M_{gpp_r} (kg · s^{-1}) Coefficient in Eq. (8), k_0 (kg · s^{-1}) Coefficient in Eq. (8), k_1 (kg · s^{-1} · MW^{-1})	42661291 12 1.059E-3 45.3 −8.07 7.63E-2	Ref. 25 Ref. 25 Ref. 26 Ref. 6 Footnote d Footnote d
Electricity Gasoline NG CO_2 Inflation Discount (WACC) Depreciation and amortization rates Tax rate	Electricity price, β_e (\$ · MW · h^{-1}) Gasoline price, β_g (\$ · kg^{-1}) NG price, β_{NG} (\$ · kg^{-3}) Unit GHG emission cost, β_c (\$ · kg^{-1}) Coefficient in Eq. (10), γ (1) i (%) r_R (%) $\rho_{da,k}$ (%) σ (%)	Fig. 3a Fig. 3b Fig. 3b 0.045 2.697867 3 5 Footnote a 35	Footnote g Footnote h Footnote f Ref. 27 Ref. 1 Sec. III.A Sec. III.A Ref. 15 Ref. 28

while Fig. 3 plots the assumed prices of NG,[f] electricity,[g] and gasoline,[h] for selected time periods. Note that 1 year of data is utilized in the simulations. Appendix A provides additional definitions regarding parameters listed in Table I as well as equations for computing capital cost and O&M cost for the NHES components.

The resulting optimal P_e for NHES_Texas is shown in Fig. 4, where Fig. 4a shows the optimal electricity delivered

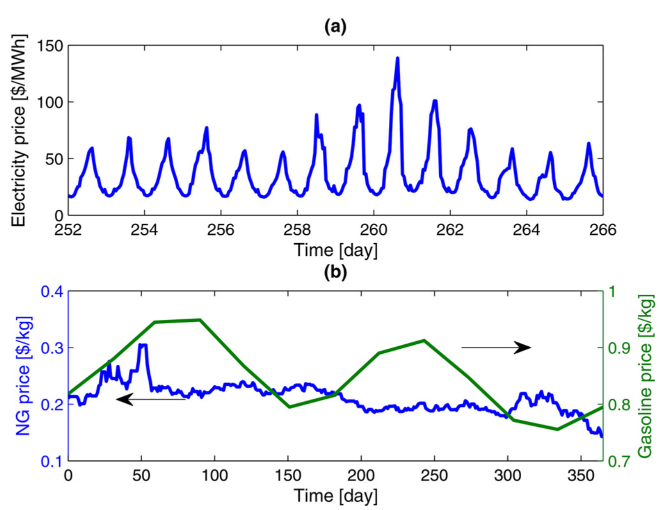

Fig. 3. (a) Electricity price for selected 14 days (NHES_Texas) and (b) NG price and gasoline wholesale price for a whole year (NHES_Texas).

[f]The NG price was downloaded from Texas Alliance of Energy Producers at http://texasalliance.org/historical-nymex-natural-gas-prices/ on February 4, 2015.

[g]Based on the day-ahead market settlement point price downloaded from ERCOT at http://www.ercot.com/mktinfo/prices/index.html on February 4, 2015. The time series is scaled by 0.75 to reflect the conservativeness of NHES_Texas in bidding.

[h]The gasoline wholesale price by a refinery was downloaded from the U.S. Energy Information Administration at http://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_STX_m.htm on February 5, 2015.

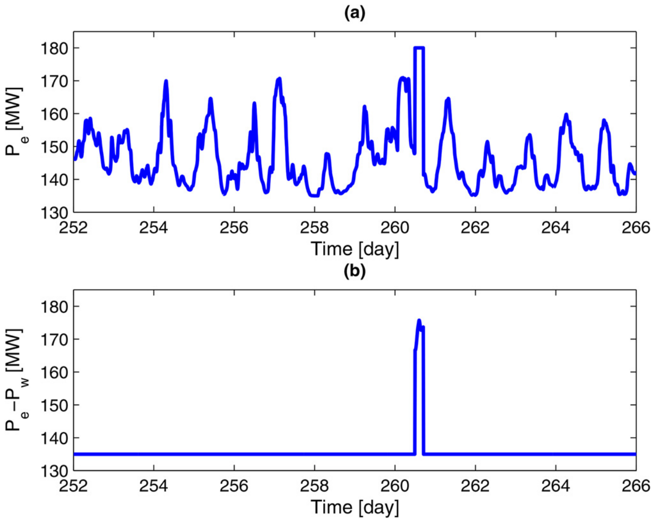

Fig. 4. Optimization result for selected 14 days for NHES_Texas: (a) Optimal electricity production and (b) electrical generation delivered to the electric grid by PHG (i.e., net load).

to the electric grid and Fig. 4b is the electrical generation delivered to the electric grid by PHG, i.e., system load minus the output from the renewable generation (or net load, $P_e - P_w$). Note that when NG is at a relatively high price, the operations optimizer prefers to produce less electricity in order to reduce the consumption of NG. When the price of NG decreases, the cost of consuming NG also decreases. In such cases, the operations optimizer chooses to increase the production of electricity by decreasing the amount of process steam diverted to GPP, which accordingly increases the amount of NG used by AHG. These results suggest that the operations optimizer tends to divert the thermal power from the nuclear reactor to GPP and only increases the electrical contribution when the price of electricity is very high (e.g., around day 260 in this example).

Remark 3: Considering the fact that the nuclear reactor can deliver a maximum rated power of 180 MW, this result suggests that for most of the time, NHES_Texas has a capacity of 45 MW for participation in operating reserve services, generating revenue from providing operating reserve services on top of the revenue from the sale of electricity. Under the current formulation, the electrical contribution increases only as a response to high electricity prices in the day-ahead market. Participation in the ancillary service market is not considered in this paper and remains an ongoing effort. Notice that this 45-MW capacity can be used for gasoline production or accordingly diverted to the electric grid as needed. As this operating reserve capacity value is limited by the rated capacity of the associated flexible load resource (FLR) (GPP in this case), higher-capacity values can be achieved by expanding its existing FLR and/or installing an additional FLR, such as a hydrogen generation plant.

To illustrate the advantage of utilizing such an operations optimizer, a simulation with constant (i.e., time-invariant) operations is conducted in which the electricity delivered to the electric grid is fixed at 171 MW constant and all the other parameters are exactly the same as the optimized case. Table II shows that the real discounted FCFF for the first year increases from \$421539071 at constant operations mode to \$428728703 (a 1.71% gain) when considering the modeled commodity market dynamics. Based on the cost parameter values reported in Table I, the payback time for NHES_Texas is ~9.34 and 9.57 years when including operations optimization or not, respectively. The IRR is 13.4% for 30 years of operations under the optimized case.[i] Note that in NHES_Texas, the gasoline production is at a constant rate (with extra energy provided by AHG), regardless of the operations. The sale of gasoline consists of >95% of the total revenue, resulting in a relatively small improvement by the proposed operations optimizer. To correctly understand the economic benefit of the proposed optimizer, Fig. 5 plots revised NPV as a function of operations time with and without the economic operations optimizer, assuming that

[i]When computing payback periods and IRR, a scaling of 95% was applied to each year's FCFF to emulate the case of outage.

TABLE II

Real Discounted FCFF for the First Year of Operations (NHES_Texas)

Economic Value	Optimal Operations	Constant Operations	Gain
Revenue: electricity	\$36898348	\$43181004	−14.55%
Revenue: gasoline	\$1218743760	\$1218743760	0.00%
Cost: CO_2	(\$10611369)	(\$15893894)	33.24%
Cost: NG for AHG	(\$18479768)	(\$27695423)	33.28%
Cost: NG for GPP	(\$351184318)	(\$351184318)	0.00%
Cost: water	(\$7770339)	(\$7770339)	0.00%
FCFF	\$428728703	\$421539071	1.71%

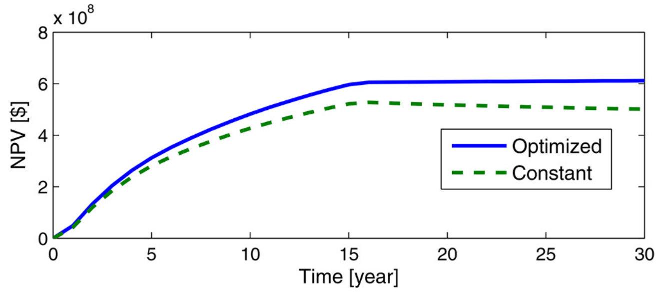

Fig. 5. Revised NPV (considering only the revenues and variable O&M cost that are related to operations) as a function of operations time (NHES_Texas).

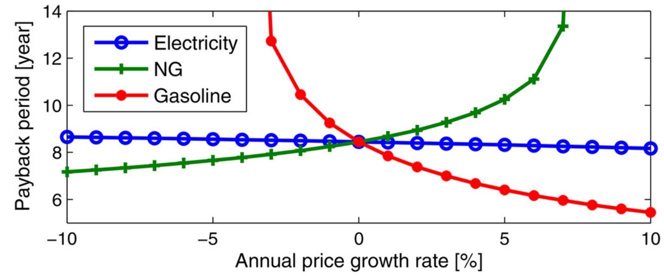

Fig. 6. Sensitivity of payback period with respect to annual price growth rate, assuming constant operations mode (NHES_Texas).

the commodity trends (e.g., price, production, and consumption) in subsequent years are the same as those assumed for the first year. This revised NPV considers only the revenues and variable O&M cost that are related to operations, including revenue from the sale of electricity and cost of consuming NG for AHG.

In order to measure the sensitivity of the economic effect of NHES with respect to commodity prices, analysis is conducted assuming the price is changing by a certain (compounded) annual growth rate. The constant operations mode is assumed for this analysis. Figure 6 shows the payback time as a function of the annual price growth rate, which suggests that the influence of the electricity price on the payback period is insignificant while the payback time is sensitive to the prices of NG and gasoline. In particular, if the price of NG increases 8% every year, or the price of gasoline decreases 4% every year, then the system may not be economically attractive.

IV.B. Optimization Results for NHES_Arizona

Table III lists all the parameter values for simulation of NHES_Arizona with their sources listed in Table III as well, and Fig. 7 plots the assumed prices of electricity[j] and freshwater[k] over selected time periods. Note that 1 year of data is utilized in the simulation. Appendix B provides additional definitions regarding the parameters listed in Table III as well as equations for computing capital cost and O&M cost for the NHES components.

The resulting optimal P_e for NHES_Arizona is shown in Fig. 8, where Fig. 8a shows the optimal electricity delivered to the electric grid and Fig. 8b is the electrical generation delivered to the electric grid by PHG, i.e., $P_e - P_s$ (or net load). These results suggest that the operations optimizer tends to use electricity for freshwater production instead of selling it to the electric grid and only increases the electricity sold to the electric grid when the price of electricity is very high (e.g., around day 178 in this example).

Remark 4: Similar to NHES_Texas, this result suggests that for most of the time, NHES_Arizona has a capacity of 30 MW to participate in operating reserve services, bringing revenue from providing operating reserve service on top of the revenue from the sale of electricity. This 30-MW capacity can be used for freshwater production or accordingly diverted to the electric grid as needed. Likewise, higher-capacity values can be achieved by expanding its existing FLR (RODP in this case) and/or installing an additional FLR, such as a hydrogen production plant.

To illustrate the advantage of utilizing such an operations optimizer, a simulation with constant operations is conducted in which the electricity delivered to the electric grid is fixed at 165 MW constant and all the other parameters are exactly the same as the optimized case. Table IV shows that the real discounted FCFF for the first year increases from \$78213987 at constant operations mode to \$140004736 (a 79.00% gain) when considering the modeled commodity market dynamics. Figure 9 plots the NPV as a function of the operations time with and without economic operations optimization, assuming that the commodity trends (e.g., price, production, and consumption) in subsequent years are the same as those assumed for the first year. Based on the cost parameter values reported in Table III, Fig. 9 indicates that the payback time for NHES_Arizona is ~17.58 years when including operations

[j]Based on the day-ahead market settlement point price downloaded from ERCOT at http://www.ercot.com/mktinfo/prices/index.html on February 4, 2015. These data are scaled so that the average of the time series conforms to the annual average bilateral price of \$36.10/MW · h for Palo Verde, Arizona, in the year 2011 (obtained from the Federal Energy Regulatory Commission at http://www.ferc.gov/market-oversight/mkt-electric/southwest/elec-sw-yr-pr.pdf on February 5, 2015). An additional scale by 0.85 is applied to the time series to reflect the conservativeness of NHES_Arizona in bidding.

[k]Based on the monthly residential price in Phoenix, Arizona, downloaded from https://www.phoenix.gov/waterservices/customerservices/rateinfo on February 5, 2015, which is scaled such that the average of the time series is \$0.6/m^3, corresponding to the cost for purchasing groundwater or surface water in Arizona.[19]

TABLE III

Parameter Values Used for NHES_Arizona

		Value	Source
Nuclear and power cycle	Unit capital cost, α_{phg} ($ · kW^{-1})	4718	Refs. 20 and 21
	Fixed O&M cost coefficient, β_{f_phg} ($ · MW · h^{-1})	27.91	Ref. 22
	Maximum power output, P_{phg_r} (kW)	180000	Ref. 6
PV station	Unit capital cost, α_{ren} ($ · kW^{-1})	5385.98	Ref. 29
	Fixed O&M cost coefficient, β_{f_ren} ($ · kW^{-1})	54.28	Ref. 30
	Maximum power output, P_{ren_r} (kW)	30000	Ref. 6
Storage	Unit capital cost, α_{ese} ($ · MW · h^{-1})	81.42	Ref. 2
	Fixed O&M cost coefficient, β_{f_ese} (%)	3	Ref. 2
	Maximum storage capacity, $\|E_{ese}\|$ (kW · h)	52700	Ref. 6
RODP	Unit capital cost, α_{rodp} ($ · kg^{-1} · s)	32076.21	Ref. 31
	Fixed O&M cost coefficient, β_{f_rodp} ($ · kg^{-1} · s)	4841.43	Ref. 31
	Variable O&M cost coefficient, β_{v_rodp} ($ · kg^{-1})	6.6E-5	Ref. 32
	Maximum production rate, M_{rodp_r} (kg · s^{-1})	15614	Ref. 6
	Coefficient in Eq. (17), k_0 (kg · s^{-1})	301.77	Footnote e
	Coefficient in Eq. (17), k_1 (kg · s^{-1} · MW^{-1})	442.20	Footnote e
	Coefficient in Eq. (17), k_2 (kg · s^{-1} · MW^{-2})	−2.16	Footnote e
Electricity	Electricity price, β_e ($ · MW · h^{-1})	Fig. 7a	Footnote j
Water	Freshwater price, β_{fw} ($ · kg^{-1})	Fig. 7b	Footnote k
Inflation	i (%)	3	Sec. III.A
Discount (WACC)	r_R (%)	5	Sec. III.A
Depreciation and amortization rates	$\rho_{da,k}$ (%)	Footnote a	Ref. 15
Tax rate	σ (%)	40	Refs. 28 and 33

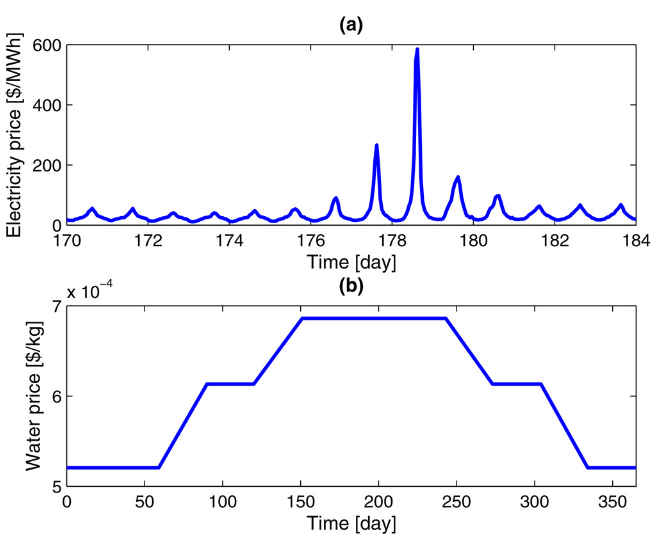

Fig. 7. (a) Electricity price for selected 14 days (NHES_Arizona) and (b) water price for a whole year (NHES_Arizona).

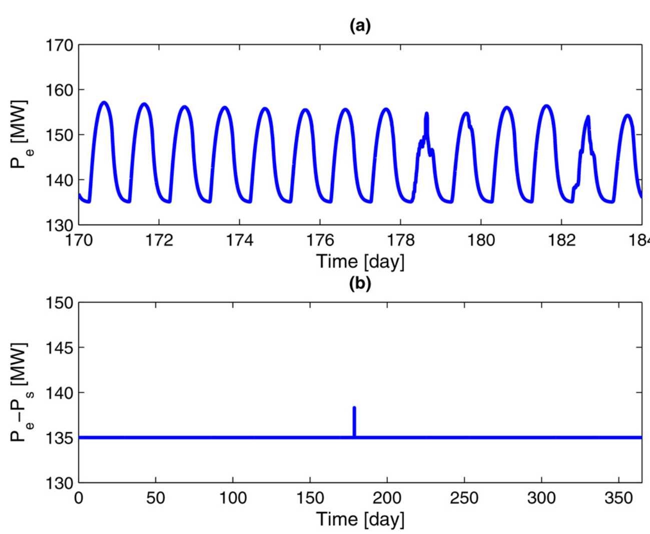

Fig. 8. Optimization result for NHES_Arizona: (a) Optimal electricity production for selected 14 days and (b) electrical generation delivered to the electric grid by nuclear reactor (i.e., net load).

TABLE IV

Real Discounted FCFF for the First Year of Operations (NHES_Arizona)

Economic Value	Optimal Operation	Constant Operation	Gain
Revenue: electricity	$39314377	$44352907	11.36%
Revenue: freshwater	$298824890	$177562621	68.29%
Cost: RODP	($32498151)	($19258994)	68.74%
FCFF	$140004736	$78213987	79.00%

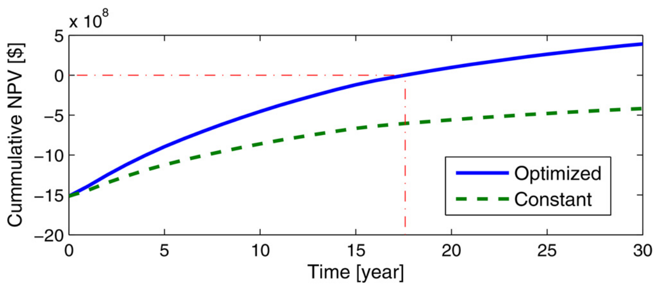

Fig. 9. NPV as a function of operations time (NHES_Arizona).

optimization. The IRR is 7.4% for 30 years of operation under the optimized case.[1]

Remark 5: Note that in this case, without the proposed operations optimizer to accommodate the high volatility in electricity and commodity market prices, NHES_Arizona is not economically attractive.

V. CONCLUSION AND ONGOING EFFORTS

Operations optimizations of two regional NHES configurations were carried out to understand various dynamic challenges and opportunities of NHESs. The selected NHES configurations include components producing electricity and variable energy generation and utilization components to yield multiple energy commodities, including chemical (e.g., gasoline) products and basic (e.g., freshwater) products. The operations optimizations are formulated and solved by both analytical and numerical approaches. The results demonstrate the improvement of NHES economic attractiveness by the proposed operations optimizer. In particular, the real discounted FCFF for the first year increases 1.71% for NHES_Texas and 79% for NHES_Arizona. The results also suggest that higher economic value can be achieved by operating the selected NHES configurations to produce alternative commodities, while minimizing its participation in the electric power market. Future efforts include conducting more comprehensive operations optimizations also considering participation in the ancillary service market, developing general operations optimization methodology for the family of NHES configurations, and implementing optimization algorithms for online optimization based on historical and predictive commodity prices and renewable generation.

[1]When computing payback periods and IRR, a scaling of 95% was applied to each year's FCFF to emulate the case of outage.

APPENDIX A

CAPITAL AND O&M COSTS FOR NHES_TEXAS

This appendix provides the equations for computing the capital and the O&M costs for the five major components of NHES_Texas, i.e., PHG (including power cycle), AHG, REN, ESE, and GPP. The parameter values used for simulation are listed in Table I.

The capital cost and the O&M cost for the nuclear and power cycle are computed, respectively, as

$$C_{phg} = \alpha_{phg} \times P_{phg\_r}$$

and

$$O\&M_{phg} = O\&M_{f\_phg} = \beta_{f\_phg} \times P_{phg\_r} \times \kappa_{year} ,$$

where

κ_{year} = number of hours during a year (i.e., 8760)

P_{phg_r} = rated maximum output power of the nuclear and power cycle

α_{phg} = capital cost per unit of installed capacity

β_{f_phg} = coefficient for fixed O&M cost.

The capital cost for AHG is computed as

$$C_{ahg} = \alpha_{ahg} \times P_{ahg\_r} ,$$

and the O&M cost is computed as

$$O\&M_{ahg} = O\&M_{f\_ahg} + O\&M_{v\_ahg} ,$$

$$O\&M_{f\_ahg} = \beta_{f\_ahg} \times C_{ahg} \ ,$$

and

$$O\&M_{v\_ahg} = \int_0^T \beta_{NG} \times M_{ahg\_NG} dt \ ,$$

where

P_{ahg_r} = rated maximum output power of AHG

α_{ahg} = capital cost per unit of installed capacity

β_{f_ahg} = coefficient for fixed O&M cost

β_{NG} = price of NG

M_{ahg_NG} = consumption rate of NG by AHG at time t.

For renewable energy generation (i.e., wind turbines), the capital cost and the O&M cost are given, respectively, by

$$C_{ren} = \alpha_{ren} \times P_{ren\_r}$$

and

$$O\&M_{ren} = O\&M_{f\_ren} = \beta_{f\_ren} \times P_{ren\_r} \ ,$$

where

P_{ren_r} = rated maximum output power of the wind turbines

α_{ren} = capital cost per unit of installed capacity

β_{f_ren} = coefficient for fixed O&M cost.

Note that for wind turbines, only the fixed O&M cost is considered while the variable O&M cost is assumed to be 0.

For ESE (i.e., the battery), its capital cost and its O&M cost are computed, respectively, as

$$C_{ese} = \alpha_{ese} \times |E_{ese}|$$

and

$$O\&M_{ese} = O\&M_{f\_ese} = \beta_{f\_ese} \times C_{ese} \ ,$$

where

$|E_{ese}|$ = rated maximum storage capacity of the battery

α_{ese} = capital cost per unit of installed capacity

β_{f_ese} = coefficient for fixed O&M cost.

Note that similar to the case of wind turbines, only the fixed O&M cost is considered for the battery while the variable O&M cost is assumed to be 0.

Finally, the capital cost for GPP is

$$C_{gpp} = \alpha_{gpp} \times M_{gpp\_r} \ ,$$

and the O&M cost is

$$O\&M_{gpp} = O\&M_{f\_gpp} + O\&M_{v\_gpp} \ ,$$

$$O\&M_{f\_gpp} = \beta_{f\_gpp} \times C_{gpp} \ ,$$

and

$$O\&M_{v\_gpp} = \int_0^T \beta_{NG} \times M_{gpp\_NG} + \beta_w M_w dt \ ,$$

where

M_{gpp_r} = rated maximum production rate of GPP

α_{gpp} = capital cost per unit of installed capacity

β_{f_gpp} = coefficient for fixed O&M cost

M_{gpp_NG} = NG consumption rate by GPP

β_w = price of water

M_w = water consumption rate by GPP at time t.

APPENDIX B

CAPITAL AND O&M COSTS FOR NHES_ARIZONA

Similar to Appendix A, this appendix provides the equations for computing the capital and the O&M costs for the four major components of NHES_Arizona, i.e., PHG (including power cycle), REN, ESE, and RODP. The parameter values used for simulation are listed in Table III.

For the nuclear and power cycle and ESE, the capital cost and the O&M cost are computed the same as for NHES_Texas, which are provided in Appendix A. The capital cost for renewable energy generation (i.e., the PV solar station) is computed as

$$C_{ren} = \alpha_{ren} \times P_{ren\_r} \ ,$$

and its O&M cost is given by

$$O\&M_{ren} = O\&M_{f\_ren} = \beta_{f\_ren} \times P_{ren\_r} \ ,$$

where

P_{ren_r} = rated nominal output power of the PV solar station

α_{ren} = capital cost per unit of installed capacity

β_{f_ren} = coefficient for fixed O&M cost.

Note that for the PV solar station, only the fixed O&M cost is considered while the variable O&M cost is assumed to be 0.

Finally, for RODP, its capital cost is computed as

$$C_{rodp} = \alpha_{rodp} \times M_{rodp\_r} ,$$

and the O&M cost is given by

$$O\&M_{rodp} = O\&M_{f\_rodp} + O\&M_{v\_rodp} ,$$

$$O\&M_{f\_rodp} = \beta_{f\_rodp} \times M_{rodp\_r} ,$$

and

$$O\&M_{v\_rodp} = \int_0^T \beta_{v\_rodp} \times M_{fw} dt ,$$

where

M_{rodp_r} = rated maximum production rate of RODP

α_{rodp} = capital cost per unit of installed capacity

β_{f_rodp} = coefficient for fixed O&M cost

β_{v_rodp} = coefficient for variable O&M cost.

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