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RESEARCH ARTICLE

Micro hydroelectric energy recovery in municipal water systems: A case study for Vancouver

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Throttling water pressure transforms useful mechanical energy into heat via a thermodynamically irreversible process. Alternatively, energy recovery hydro turbines or pumps as turbines can be used to generate power from excess water pressure. This study investigates the influence of water system and turbine characteristics on the economic feasibility of energy recovery turbines and develops general design principles that benefit infrastructure planners who may consider energy recovery within water systems. Results indicate economic feasibility is predictably influenced by a variety of factors. For instance, service reservoirs can decrease the levelized cost of electricity in the range of 10% and provide some generation dispatchability. Smaller turbines decrease the levelized cost of electricity in the range of 30%, but sacrifices energy recovery potential. Although challenges exist, energy recovery turbines can be an economical, flexible, and renewable option for controlling pressure and deserve serious consideration within some water supply systems.

Keywords: hydro power; renewable energy; energy storage; hydro turbines; water distribution systems

1. Introduction

Hydroelectric power has traditionally been generated in thousands of megawatts from dedicated installations. These large-scale hydro facilities require major financial investments, may take many years to construct, permanently disrupt river ecosystems, and can flood large areas of land. Economic, environmental, and social concerns are significant barriers to building major new hydroelectric plants. In contrast, energy recovery turbines (ERTs) installed in existing municipal water supply systems are a small-scale option for harnessing hydroelectric potential that overcomes many of these limitations (European Small Hydro Association, 2010).

This paper investigates the influence of both a regional water system and turbine characteristics on ERT economic feasibility and develops general design principles pertinent to infrastructure planners. A hypothetical water system for Vancouver British Columbia is first analysed to determine ERT potential. Subsequently, the sensitivity of ERT economic feasibility to system and turbine characteristics is discussed and preliminary design trade-offs are quantified.

1.1 Description of ERTs

ERTs are micro hydro turbines installed in urban water systems at locations where throttling of pressure is beneficial or required. Without ERTs, the pressure has traditionally been throttled solely using pressure reducing valves (PRVs), which dissipate the energy associated with the flow across the pressure differential. By contrast, ERTs aim to recover a portion of the energy into electrical power, which is fed back onto the electrical grid. Like PRVs, ERTs are operated to maintain a given downstream pressure. In fact, a PRV is usually installed in parallel with ERTs to bypass flows in excess of turbine capacity and to sustain system operation during turbine maintenance (European Small Hydro Association, 2010). Typical locations for ERTs are directly upstream of a water treatment plant, upstream of a service reservoir, or in-line with distribution piping (Afshar, Ben Jemaa, & Marino, 1990; Wallace, 1996; European Small Hydro Association, 2010) (Figure 1). ERTs perform best in systems where substantial throttling of pressure is required; these are typically gravity-fed systems supplied from reservoirs at high-elevations, although there are times when even a pump system might benefit from a strategic energy recovery approach, particularly when pumping over a hill when considerable residual energy is available at the downstream end of the supply line. Examples of ERTs within water supply systems in North America (Bodin, 2008; White, 2011), Europe (European Small Hydro Association, 2010; Choulot, Denis, & Punys, 2012), and Australia (WaterWorld, 2010) range from 40 kW to 5 MW. Although this study focuses on ERTs in water supply systems, ERTs have also been applied in irrigation, wastewater, and industrial water systems (Singh & Cabibbo, 1980; Bansal & Marshall, 2009; European Small Hydro Association, 2010; Patel, 2010; Stevanovic, Gajic, Savic, Kuzmanovic, & Arnautovic, 2011).

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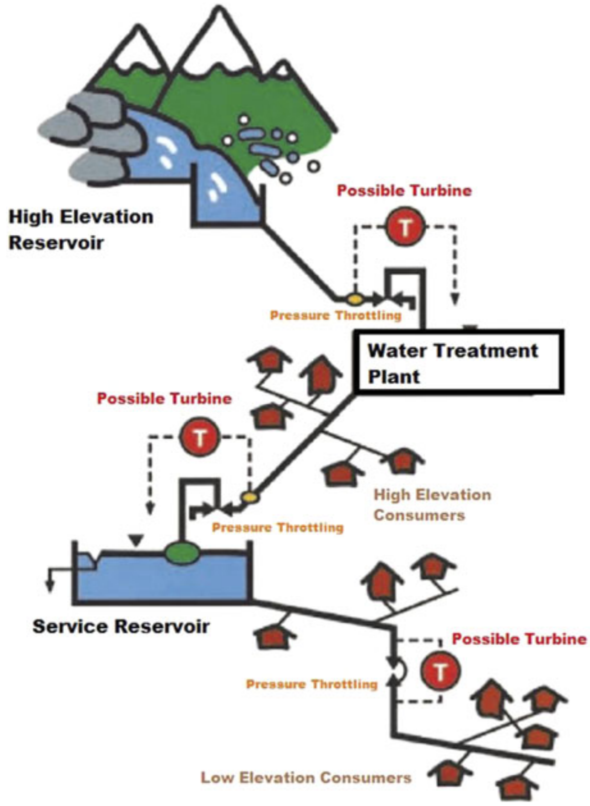

Figure 1. Typical ERT locations within water supply system. Adapted from European Small Hydro Association (2010).

1.2 Advantages of ERTs

ERTs produce renewable power and, depending on configuration, potentially dispatchable power that can enable greater adoption of non-dispatchable renewable resources. Fundamentally, traditional and run-of-the-river hydro occupies the natural environment whereas ERTs occupy an artificial environment. The installation of ERTs in urban settings minimizes environmental impacts, reduces the need for geological and hydrological site studies, and allows for minimal transmission costs. The use of treated water eliminates the need for debris and sedimentation control, and the possible use of existing piping can drastically reduce penstock costs. While ERTs are more expensive than large-scale hydro on a per MW capacity basis, ERTs are smaller installations that require substantially smaller capital investment. This is advantageous for jurisdictions lacking political or financial capability to make large investments or jurisdictions pursuing incremental growth.

1.3 Literature review

Basupi, Kapelan, and Butler (2014) and Filion, MacLean, and Karney (2004) have recognized energy recovery as a contributing factor in analysing life cycle energy use of water distribution systems. Basupi et al. (2014) incorporated energy recovery into a design optimization process using the methods developed by Filion et al. (2004). Zakkour, Gaterell, Griffin, Gochin and Lester (2002) have estimated 17 MW of energy recovery potential in the UK water industry; Switzerland has already developed 90 sites in its drinking water system, and European Small Hydro Association (2010) estimates 38.9 MW of additional potential in 380 remaining undeveloped sites.

The performance and practical implementation considerations of ERTs are best documented by industry, as opposed to academic, literature on small and micro hydro turbines. Most notably, European Small Hydro Association (2010) have identified potential for energy recovery in water systems and provides guidelines on equipment selection, the development process, and examples of European projects; however, it does not address the system-level considerations pertinent to infrastructure planners. European Small Hydro Association (2004) is a detailed reference on the technical aspects of small hydro projects. Although European Small Hydro Association (2004) does not specifically address ERTs, some of the material is applicable. Other industry publications also document ERT projects. However, it is typically difficult to discern technical details or general insights from these commercially motivated articles (Bodin, 2008; WaterWorld, 2010; White, 2011). In the context of current academic literature, ERTs most closely relate to pumps as turbines (PATs). PATs are pumps installed in reverse to recover energy in water systems. PATs and ERTs use analogous physical principles to recover energy from pressure differentials and share many of the same operating characteristics and considerations. Ramos and Borga (1999) and Ramos, Mello, and De (2010) presented PATs as an alternative to PRVs and characterized the performance of PATs within water distribution systems. Williams, Smith, Bird, and Howard (1998) and García, Marco, and Santos (2010) documented PAT performance for actual installations in the UK and Spain, respectively. Existing documentation of specific ERT/PAT projects seldom provide comprehensive understanding of the technical factors relevant to infrastructure planners that influence incorporation of ERTs into water systems. Accordingly, a current objective is to extend understanding by developing general design principles.

At the system-level, the difference between ERTs and PATs largely reduces to a trade-off between capital cost and efficiency; ERTs have higher capital costs than PATs, but also operate at higher average efficiency. As a result of the underlying similarities, ERTs or PATs can be used interchangeably in some high-level methodologies (Filion et al., 2004; Basupi et al., 2014). Fontana, Giugni, and Portolano (2012) investigated the potential of installing ERTs/PATs in Naples' water distribution system and found favourable payback periods in the range of 3 years for many sites. Afshar et al. (1990) and Boillat, Bieri, and Dubois (2010) have developed algorithmic approaches that aid in determining optimal locations of ERTs within water supply networks. While the algorithmic approach implicitly addresses some physical limitations and design trade-offs inherent to ERTs, planners would benefit from explicit treatment of these topics. Ultimately, the design of water systems with ERTs will be based on the professional judgement of infrastructure planners in addition to opaque computational processes.

2. Case study for Vancouver

2.1 *Study area*

Intuitively, most hydroelectric recovery potential is in mountainous or hilly terrains where low-lying populations are served by high-elevation reservoirs. The Greater Vancouver Region is an example of such a favourable topography. The majority of Greater Vancouver's population resides less than 100 m above sea level. The region is served by three reservoirs to the north of the city: Capilano at 160 m top water level (TWL), Seymour at 218 m TWL, and Coquitlam at 152 m TWL (Metro Vancouver, 2011a). In general, the elevation drops towards the south. In addition to the availability of high-level reservoirs, Greater Vancouver was also chosen for the case study because of its size. The Vancouver Metropolitan Area has 2.3 million inhabitants and is the third most populous in Canada. There is sufficient population to explore economies of scale and sufficient geographic extent to study the impact of friction losses and ERT system granularity.

For the case study, a hypothetical water system is imposed on the region served by the Capilano reservoir. The choice of a hypothetical system enables a straightforward and transparent analysis focusing on the pertinent considerations that are generally applicable to other municipalities. The hypothetical system also facilitates a diverse range of site characteristics that yield broader insight into ERTs within water systems. While the simplified hypothetical system may be sufficient for planning-level analysis of regional energy recovery potential, comprehensive knowledge of the existing system would be needed for detailed design of individual ERT facilities.

2.2 *Economic analysis*

2.2.1 *Method*

ERT economic feasibility is calculated using a previously documented method (Su & Karney, 2013), summarized and presented here. The method aims for simplicity to enable planners to quickly evaluate ERT economic feasibility early in the planning process using minimal data, yet provides sufficient detail to illustrate high-level design trade-offs. For each site, the turbine rated head H_r is

$$H_r = L_r - L_p - H_p - H_d - H_{ut} \tag{1}$$

where L_r = reservoir TWL (m), L_p = peak elevation in the turbine's service area (m), H_p = total piping friction loss between reservoir and site (m), H_d = delivery pressure (m), and H_{ut} = head of upstream turbines (m).

An annual hydrograph for the site $G(t)$ (m^3/s) is calculated from typical diurnal and seasonal flow patterns, and is used to find Q_r = the turbine rated flow (m^3/s) such that E_a = annual energy produced by the turbine (J) is maximized.

$$Q_r \text{ s.t. } \max\left[E_a = \int k(Q_r \cdot G) \cdot \eta \cdot d \cdot G \cdot g \cdot H_r \, dt\right] \tag{2}$$

where η = turbine efficiency, d = density of water (kg/m^3), g = gravitational acceleration (m/s^2), and $k(Q_r, G(t)) = 1$ when $G(t)$ is within turbine flow tolerance range and $k = 0$ otherwise.

The primary economic feasibility indicator analysed in this paper is the annual kWh produced per dollar initial capital cost (kWh/dollar, K_d (kWh/$))

$$K_d = E_a/(3.6 \cdot 10^6 \cdot F_c(H_r, Q_r)) \tag{3}$$

where $F_c(H_r, Q_r)$ is the cost function for the ERT facility. kWh/dollar is inversely proportional to the levelized cost of electricity (LCOE) by

$$\text{LCOE} = (1/K_d) \cdot [(C \cdot (1+C)^N)/((1+C)^N - 1)) + M] \tag{4}$$

where C = annual cost of capital as a fraction of initial capital cost, N = lifetime (years), and M = annual maintenance cost as a fraction of initial capital cost.

The presented method as applied for the case study is more detailed than that employed by Basupi et al. (2014) and Filion et al. (2004) for life cycle analysis due to inclusion of time varying flow patterns, turbine flow tolerance, and use of finer (hourly) time resolution. The twin effects of flow variability and turbine tolerance guides selection of turbine type and location, as described in Sections 3.1, 3.3, and 3.4. Fontana et al. (2012) used an EPANET model of a complete water network to simulate changes in head and incorporates varying turbine efficiency based on a PAT model. The presented framework supports analytical descriptions of head and efficiency; however, the case study assumes constant values for those parameters. Such simplifications allow utilization of the method earlier in the planning process, without need for network modelling and turbine selection, and are vital for assessing systems with minimal data.

2.2.2 Results

The initial turbine placements for the hypothetical system are shown in Figure 2. Turbines for Region J and Region K are placed in series. In general, turbines in a water supply system are installed directly in a distribution line, upstream of a water treatment facility, or upstream of a service reservoir (Afshar et al., 1990; Wallace, 1996; European Small Hydro Association, 2010).

The site head and flow are determined from topographic and population data for each location. The head available to each turbine under consideration is calculated using Equation (1) and shown in Table 1, and is assumed to be constant. A 25 m minimum service pressure is assumed (Ontario Ministry of the Environment, 2008) and a 0.8 m per km friction loss is estimated based on pipe diameters and flow rates from Metro Vancouver for selected water mains (Metro Vancouver, 2011b).

Average site flow given in Table 1 is the product of the average per capita consumption and turbine downstream population (Metro Vancouver, 2011c). Due to the series connection, the flow through Site J is the coincident demand of Region J and Region K. Turbine flow can vary considerably throughout each day and throughout the year, and these periodic variations impact turbine performance as per Equation (2). A typical municipal diurnal pattern is used (CBCL Consulting Engineers, 2011) in conjunction with a seasonal pattern specific to Vancouver (Metro Vancouver, 2011c) that is adjusted for the downstream population size of each site. The diurnal and seasonal patterns are merged to produce flow duration curves and hydrographs for each site. Flow duration curves are explained in European Small Hydro Association (2004). A sample flow duration curve is given in Figure 3.

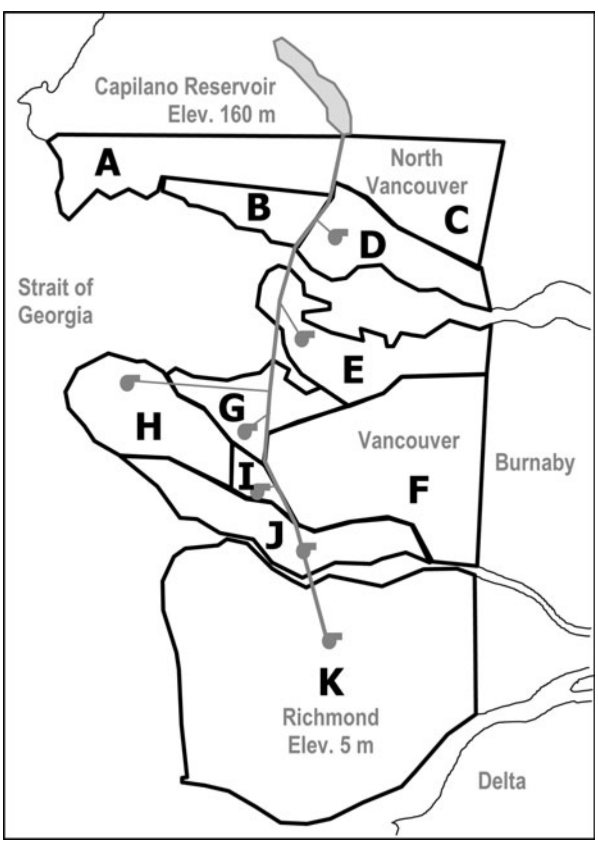

Figure 2. Turbine locations and downstream regions.

Table 1. Turbine site characteristics.

Region	Population	Average site flow (MLD)	Peak elevation (m)	Piping head loss (m)	Available turbine head (m)
A	19200	9	>200	15	Pumping required
B	30750	15	140	10	Pumping required
C	45950	22	>200	10	Pumping required
D	37800	18	120	10	5
E	159300	78	60	20	55
F	183000	89	120	30	Pumping required
G	81350	40	60	20	55
H	34950	17	100	25	10
I	10500	5	80	30	25
J	72100	112	60	30	45
K	156900	77	5	40	45

From turbine head and flow, iterative calculations find the optimal turbine rated flow producing maximum annual energy output. For preliminary design purposes, the turbine operating range is estimated to be + 5 to − 30% of rated flow. Water to wire efficiency is estimated to be a constant 80%. A parallel turbine and pressure reducing valve (PRV) configuration is assumed. Figure 3 illustrates the possible modes of operation and relative frequency of occurrence, using Turbine G as an example. Turbine sizing results using Equation (2) are summarized in Table 2.

Once the turbine has been sized, its cost is estimated. In North America, there are few ERT projects; run-of-the-river hydro projects are relatively more established. Hence, in lieu of cost data for ERT projects, the cost function F_c used in Equation (3) is calculated using regression analysis on a series of cost estimates by BC Hydro for run-of-the-river hydro projects in British Columbia under 2 MW (British Columbia Hydro and Power Authority, 2000). The regression model is based on a form used by Ogayar and Vidal (2009), with additional terms for penstock and transmission distance. The additional terms are necessary because, unlike run-of-the-river hydro, penstock and transmission costs are minimal for ERTs.

$$F_c = 46700 \cdot P_r^{0.89} \cdot H_r^{-0.50} + 1290 \cdot D_p + 84 \cdot D_t \qquad (5)$$

where P_r = turbine rated power (kW), H_r = turbine rated head (m), D_p = penstock length (m), D_t = transmission

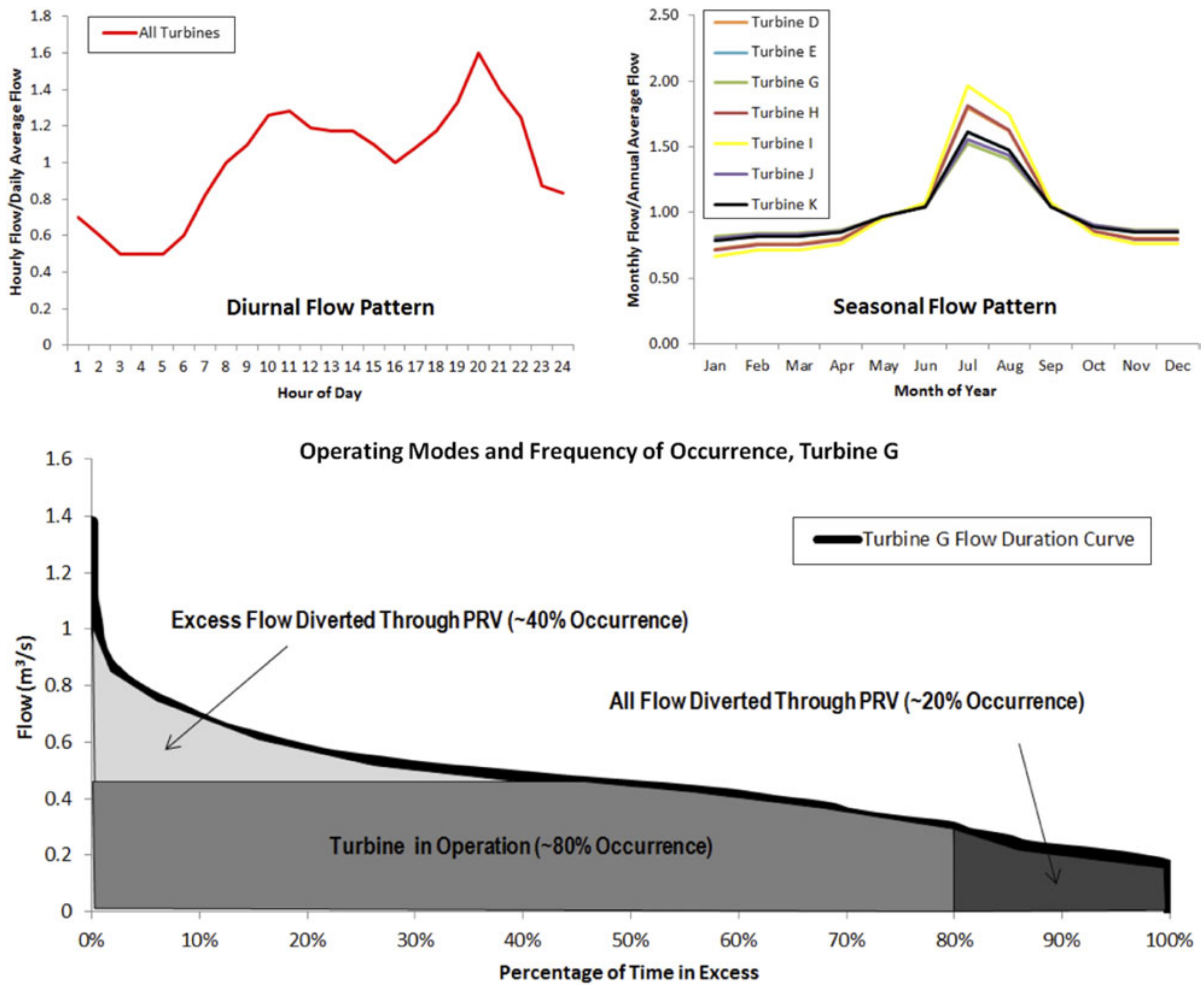

Figure 3. Flow patterns and operating modes.

distance (m), and capital cost F_c is in 2012 Canadian dollars. The results of applying Equation (5) with $D_p = D_t = 0$ are shown in Table 2. The results are comparable to cost estimates using the RETScreen 4 software (Natural Resources Canada, 2012). The cost function is a prefeasibility/feasibility estimate with a precision of perhaps half an order of magnitude.

kWh/dollar and LCOE are calculated using Equation (3) and Equation (4) respectively; results are summarized in Table 2. LCOE shown in Table 2 assume 5% cost of

Table 2. Turbine sizes and economic feasibility of selected sites.

Region	Rated flow (m^3/s)	Rated head (m)	Capacity factor	Turbine size (kW)	Capital cost	kWh/Dollar	LCOE ($/kWh)
A	–	–	–	–	–	–	–
B	–	–	–	–	–	–	–
C	–	–	–	–	–	–	–
D	0.27	5	65%	9	$151,000	0.35	0.195
E	1.12	55	79%	369	$1,210,000	2.08	0.033
F	–	–	–	–	–	–	–
G	0.57	55	80%	188	$666,000	1.96	0.035
H	0.22	10	65%	17	$184,000	0.52	0.131
I	0.07	25	73%	11	$79,000	0.88	0.078
J	1.61	45	80%	433	$1,550,000	1.93	0.035
K	1.11	45	79%	297	$1,110,000	1.84	0.037

capital, 1% of original capital cost for annual operation and maintenance, and 40 year lifetime. The LCOE can be used to compute various return on investment metrics given an electricity rate. Electricity rates are dependent on policy and may vary from jurisdiction to jurisdiction. Rates are typically around \$100/MWh in jurisdictions where feed in electricity rates for renewable power exist. However, rates can reach \$300 to \$400 in some jurisdictions (Su & Karney, 2013). In comparison, Fontana et al. (2012) estimated 1.5 to 2 kWh/dollar for PATs in Naples.

Ascertaining the economic feasibility of ERTs is an iterative process. The planner first establishes initial locations, then assesses turbine head, flow, size, cost, and economic feasibility. Accordingly, the planner decides whether the initial choice of the turbine location was appropriate and may readjust the location and re-evaluate.

3. Design considerations

3.1 Geography, topography, and turbine system granularity

The geographic extent of the water supply system primarily influences the head available to the turbines by impacting pipe length and piping friction losses. Designers can control friction loss whereas the pipe length is a geographically defined variable. Friction losses are directly subtracted from available head for ERTs. In the Greater Vancouver Region, piping friction loss was provisionally taken to be 10 m for Turbine D and 30 m for Turbine F, with the difference due to distance from the Capilano Reservoir. Hence, even though Region D and Region F had the same peak elevation, energy could be recovered from Region D but pumping was required for Region F. For all sites evaluated, piping friction loss is significant compared to turbine head; thus, the feasibility of energy recovery turbines is constrained by choices in pipe sizing, material, and layout, which all contribute to piping friction losses.

Topography, specifically the elevations throughout the water supply system, shapes the granularity of the turbine system. It is beneficial for individual turbines to serve an area with uniform downstream elevation because any water consumption below peak elevation represents forgone energy recovery potential. Therefore, turbines should be located to enclose areas of similar elevation. It is easier to find small areas of uniform elevation than large areas; hence, a greater portion of a region's energy recovery potential is utilized using smaller turbines and increased system granularity. However, larger turbines – and thus implicitly providing decreased granularity – yield better economies of scale. Larger downstream populations also increase capacity factor by increasing usage diversity and consequently reducing flow variations (Figure 3). These trade-offs in system granularity is inherent to all ERT systems.

Table 3. Economic effects of turbine aggregation.

Region	Flow (MLD)	Turbine head (m)	Turbine size (kW)	kWh/Dollar
E	78	55	369	2.08
G	40	55	188	1.96
I	5	25	11	0.88
J (series)	112	45	433	1.93
K (series)	77	45	297	1.84
E + G	118	55	557	2.20
G + I	45	25	97	1.23
J (direct)	35	45	136	1.70
K (direct)	77	90	594	2.80

For example, consider Region E and Region G; both have 55 m of available turbine head. The regions have kWh/dollar values of 2.08 and 1.96 respectively. If the two regions were joined, the resulting turbine installation would still have 55 m of turbine head. The new kWh/dollar value will be 2.20, which is greater than either of the initial regions. At \$0.10/kWh, 5% cost of capital, and 1% annual maintenance, the aggregation parallels combining two investments with discounted paybacks of 6.0 years and 6.4 years into a single investment that pays back in 5.6 years (Table 3).

In contrast, consider Regions G and I with turbine heads of 55 m and 25 m respectively. Due to the difference in peak elevation, downstream pressure must be sufficient to serve all end users; the resulting turbine head must be the smaller of the two, 25 m, to accommodate the highest downstream location (Table 3). Consequently, the single turbine will recover less energy than the two smaller turbines together and some energy recovery potential is forgone. In this case, the single installation will also yield a less favourable kWh/dollar value than if the regions were developed separately. The head, flow, and economic interrelation is graphically depicted in Figure 4.

Turbines may connect to the water system in series or directly; Table 3 compares these two configuration options for Regions J and K. In series, the two sites yield an aggregate kWh/dollar value of 1.89 while direct connections yield an aggregate value of 2.50. In general, when two turbines in series are changed to direct connections, one turbine will see a drop in flow at the same head and the other will see a rise in head at the same flow (Figure 4). As a result, one turbine moves to a more favourable kWh/dollar value and the other moves to a less favourable kWh/dollar value. The recoverable energy is independent of whether a series or direct configuration is used.

The only information specific to Vancouver in the kWh/dollar contours presented in Figure 4 is flow variability and, to a lesser extent, capital cost. The contours presented may be applied to other systems with reasonably accuracy. Systems with variability less than

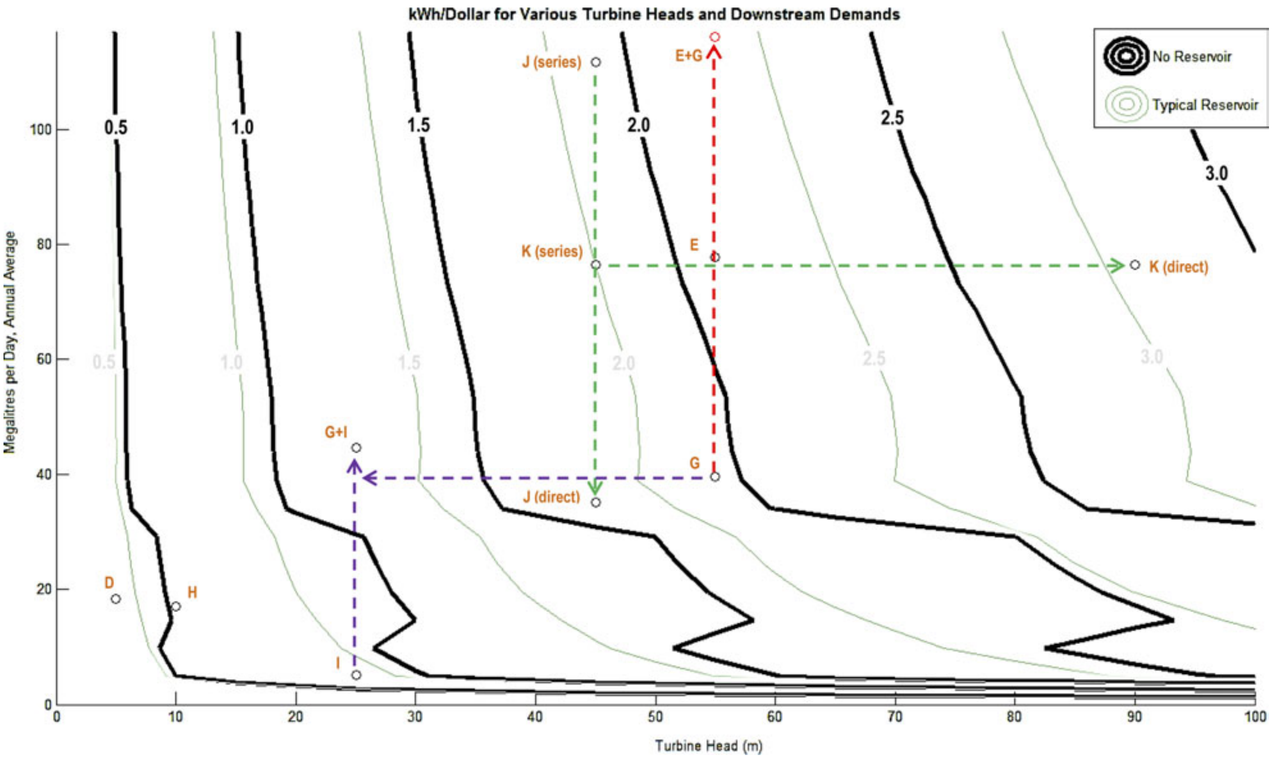

Figure 4. kWh/Dollar for various turbine heads and downstream demands. Note the general tendency towards more favourable kWh/Dollar with higher flow, higher head, and availability of a service reservoir. Red arrows illustrate the impact of combining Turbines G and E into a single Turbine E + G. Purple arrows illustrate the impact of combining Turbines G and I into a single Turbine G + I. Green arrows illustrate the impact of changing Turbines J and K from a series configuration into a direct configuration.

Vancouver will tend to reach kWh/dollar values closer to the "Typical Service Reservoir" contours. Systems with more variability will tend to reach kWh/dollar values less favourable than the "No Reservoir" contours. Both contours are directly proportional to capital cost. The effect of service reservoirs is discussed in Section 3.3.

Non-economic factors also limit site choice and consequently turbine aggregation levels. Pragmatically, ERTs will be located at existing large PRV stations that are also suitable for expansion. The design team should consider the number of sites that will ultimately be developed and the timespan of the planning in order to weigh economic benefits for the present against preservation of regional energy recovery potential for the future.

3.2 Leakage and delivery pressure

Brothers (2001) suggests that some utilities in North American lose 20% to 50% of water through leakage. Leaked water is treated and partially distributed in the system, but is not metered and billed to the consumer and hence is a cost to the water utility. Utilities implement various leakage reduction measures to reduce this cost. However, when energy recovery is present in the water system, a portion of the leaked water will also provide revenue by flowing through an ERT and generating power prior to leakage.

The question arises of whether utility leakage reduction measures should be deterred by ERTs. The revenue per volume of water through an ERT can be compared to the cost per volume of leakage. In 2012, Metro Vancouver charged on average \$0.60/m^3 to its water customers (Metro Vancouver, 2012). Perhaps about \$0.06/m^3 is directly attributable to the incremental cost of supplying water and thus approximates the cost of leakage. Table 4 summarizes the energy recovered per cubic meter for each turbine. With electricity at \$0.10/kWh, the more favourable sites approach revenues of \$0.01/m^3. Compared to \$0.06/m^3 for leakage, it is evident that energy

Table 4. Energy recovered per volume of flow.

Region	Volume (10^6m^3/Year)	Turbine head (m)	Energy recovered (MWh/Year)	Energy per volume (kWh/m^3)
D	6.7	5	53	0.008
E	28.4	55	2500	0.089
G	14.5	55	1300	0.090
H	6.2	10	96	0.015
I	1.9	30	70	0.037
J	41.0	45	3000	0.073
K	28.0	45	2000	0.073

recovery offsets a small portion of leakage costs and accordingly reduces the financial effectiveness of leakage reduction measures downstream of the turbine. Revenue per volume is most heavily dependent on turbine head; should head in the hundreds of meters be available, the cost of leakage may possibly be completely offset.

The relationship between leakage and energy recovery involves additional trade-offs. In lieu of locating and fixing leaks, utilities control leakage volume by reducing pressure. System pressure may be reduced during off peak hours (maintaining constant delivery pressure) or delivery pressure itself may be permanently reduced. In a system with energy recovery, pressure is partially controlled via ERTs; while a reduction in pressure decreases flow due to decreased leakage and consumption, it compensates with increased turbine head. The increase is due to lower piping friction losses and lower delivery pressure at the end consumer. In Vancouver, the delivery pressure is significant relative to all turbine heads.

Leakage in piping may attenuate transients by acting similarly to pressure relief valves. On the other hand, the additional complexity introduced by ERT operation may act as a source or sink for transient pressures. While analysis of transients is beyond the scope of high-level planning, designers of ERT installations should be aware of the attenuation effect of leaky pipes and how repair or additional leakage in the future may influence the transient response of the system.

3.3 Service reservoir effects

In typical water supply systems, service reservoirs store water within the system for the purpose of meeting peak and contingency demands. Service reservoirs act to decouple the turbine from the consumption. By doing so, service reservoirs downstream of turbines attenuate demand variations and increase turbine capacity factors.

A common location for an ERT is directly upstream of a service reservoir (European Small Hydro Association, 2010). However, constructing a reservoir solely for the purpose of increasing ERT capacity factors is uneconomical, as fixed costs exceed 1 million for even small installations. Therefore, the reservoir would have to be needed for other purposes. Table 5 and Figure 4 compare the capacity factor and kWh/dollar for the assessed sites, with and without reservoirs. The kWh/dollar figure does not include reservoir cost. Table 5 assumes a "typical" reservoir volume that is 25% of peak day volume, exclusive of contingency allowances (Trifunovic, 2006; Ratnayaka, Brandt, & Johnson, 2009), and a linear control scheme where flow is proportional to reservoir level (Su & Karney, 2013). The impact of the reservoir is simulated over a year; an example of turbine flows with and without a reservoir is given in Figure 5.

For the turbines analysed, having a reservoir increased capacity factor by 1.04 times to 1.23 times, increased energy recovered by 1.04 times to 1.09 times, and increased the overall kWh/dollar value by 1.05 times to 1.21 times.

Reservoirs are sized at 25% of peak day volume for reasons other than energy recovery. It may be possible that marginal increases in reservoir size would benefit energy recovery. In this scenario, the marginal cost of size increases would be attributed to the ERT project. As shown in Figure 6 for Turbines E, G, and H, there is no economic benefit to increasing reservoir size beyond the typical size in terms of energy recovery, even when assuming an optimistic service reservoir marginal cost of \$50/m^3.

Decoupling turbine flow from demand flow also allows the turbine to be (at least partly) operated as a dispatchable source of power. In the current electrical grid, a major barrier facing non-dispatchable renewable technologies such as wind and solar is the need for additional dispatchable generation or energy storage. ERTs upstream of service reservoirs can therefore enable greater adoption of non-dispatchable renewable technologies by generating electricity (i.e., filling reservoirs) when non-dispatchable power is lacking and shutting down (i.e., draining reservoirs) when there is excess non-dispatchable power. Given that reservoirs are typically sized based on maximum day demand, it follows that turbines installed upstream of most reservoirs would have the capability to dispatch

Table 5. Effect of service reservoirs on upstream turbines.

	No reservoir			Typical sized reservoir			
Region	Turbine size (kW)	Capacity factor	kWh/Dollar	Reservoir size (m^3)	Turbine size (kW)	Capacity factor	kWh/Dollar
D	9.2	65%	0.35	7000	8.0	80%	0.42
E	369	79%	2.08	30000	369	85%	2.25
G	188	80%	1.96	15000	188	88%	2.14
H	17	65%	0.52	6500	15	80%	0.63
I	11	73%	0.88	2000	11	76%	0.92
J (series)	433	80%	1.93	43000	433	87%	2.11
K (series)	297	79%	1.84	29000	297	85%	1.98
J (direct)	136	80%	1.70	13000	136	86%	1.85
K (direct)	594	79%	2.80	29000	594	85%	3.03

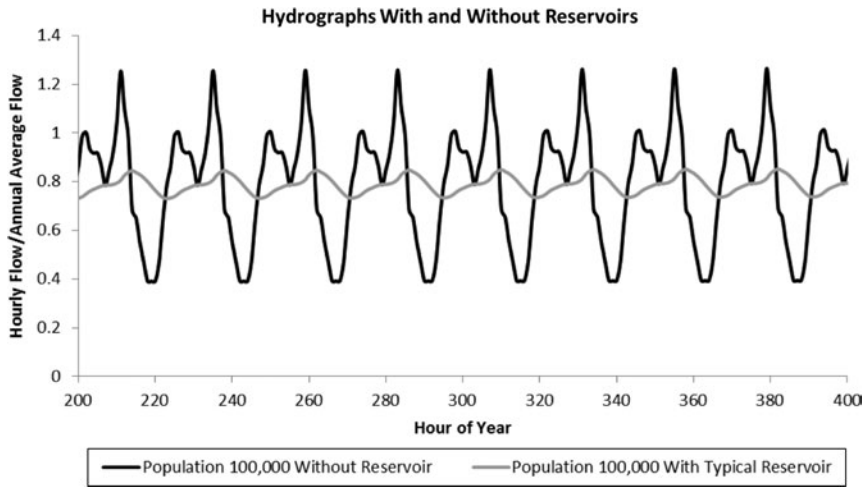

Figure 5. Hydrograph with and without reservoirs.

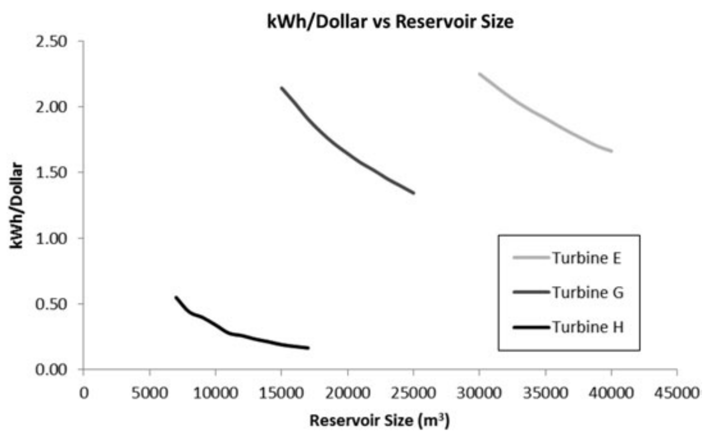

Figure 6. kWh/Dollar vs. reservoir size.

power over a daily cycle. Similar operation is common in traditional water supply systems where reservoirs are filled by pumping during off-peak hours when electricity is the cheapest. With dispatchability, ERTs can also take maximum advantage of time of day tariffs, where available.

3.4 Impact of turbine tolerance to variability

All analyses thus far have assumed that the turbine can operate from 5% above rated flow to 30% below rated flow. Due to demand variations, turbine flow tolerance impacts energy recovery by affecting the fraction of annual consumption volume that is recovered through the turbine. Figure 7 shows this fraction as a function of normalized turbine flow tolerance, for two different downstream populations with and without reservoirs. The normalized turbine flow tolerance is defined as $(Q_{max} - Q_{min})/(0.5 \cdot (Q_{max} + Q_{min}))$ where Q_{max} = maximum turbine flow and Q_{min} = minimum turbine flow.

Increasing flow tolerance will increase the fraction of volume recovered, and the relationship is roughly linear in the range considered. However, changing the turbine flow tolerance may involve using different turbine types. Therefore, translating the fraction of annual volume recovered into energy recovered will involve estimating reasonable weighted average efficiencies for different turbine types. The model's estimate of 80% efficiency is specific to a Francis turbine with a normalized tolerance of 0.4 (+5% to −30%). Flow through the site cannot be as easily controlled as for traditional hydro and hence the turbines best suited for energy recovery are those which maintain acceptable efficiency through a large range of flows. The specific relationship in Figure 7 between flow tolerance and recovery volume is specific to the model's demand pattern; however, the general positive relationship will hold true upon condition that there exists variation in downstream demand.

Multiple turbines in parallel also increase the range of acceptable flows. Figure 8 illustrates an example of Site G

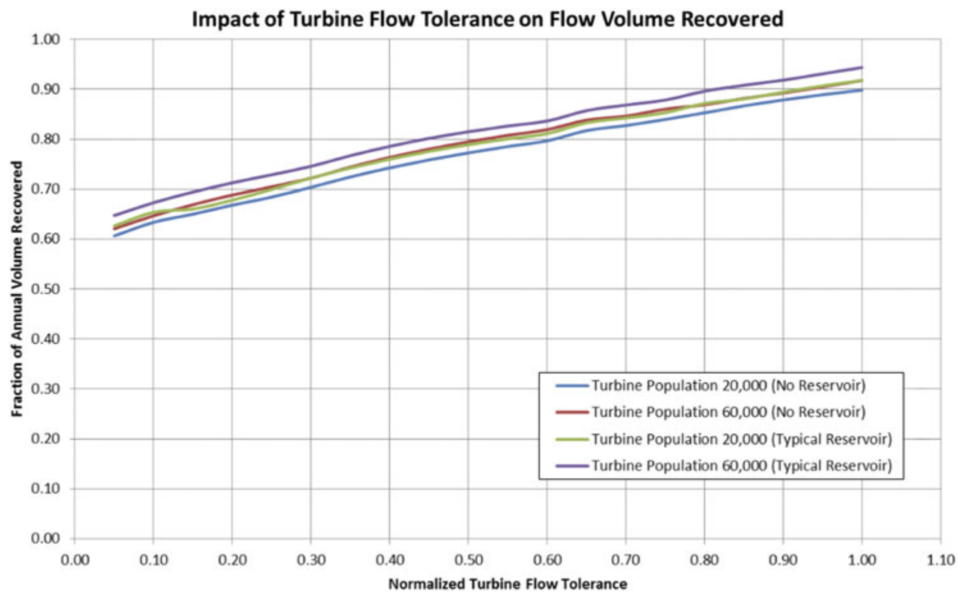

Figure 7. Impact of turbine flow tolerance on flow volume recovered.

with two identical turbines, each with a flow range of $0.2\,m^3/s$ to $0.4\,m^3/s$. Figure 9 illustrates another example where the parallel turbines have a smaller flow range of $0.2\,m^3/s$ to $0.3\,m^3/s$ each. Where parallel turbines have smaller flow ranges, PRV operation is necessary for intermediate demands.

3.5 Turbine sizing for optimal kWh/dollar

Thus far, turbine sizing has been based on recovering the maximum amount of energy possible. Sizing based on maximum energy recovery is a function of the flow duration curve but not cost. This section investigates the alternate sizing objective of achieving maximum kWh/dollar rather than maximum energy recovery. Figure 10 compares the fraction of total energy recovered (effectiveness) and kWh/dollar for a variety of sizes of Turbine G. Results for other turbines show a similar trend and are summarized in Table 6. Turbines upstream of service reservoirs also show similar results when kWh/dollar and effectiveness are compared for a range of sizes. Effectiveness is defined as $E_a/(d \cdot g \cdot H_s \cdot V_a)$ where $E_a =$ annual energy produced by turbine (J), $d =$ density of water (kg/m^3), $g =$ gravitational acceleration (m/s^2), $H_s =$ site available turbine head (m), and $V_a =$ annual consumption volume (m^3).

Evidently, sizing turbines for maximum kWh/dollar can yield substantially higher kWh/dollar values than when sizing for maximum effectiveness. For the larger and

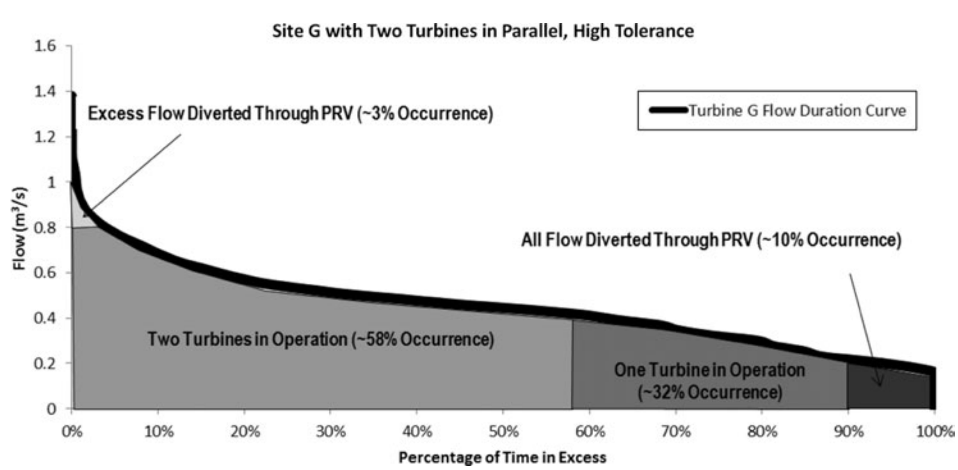

Figure 8. Modes of operation and frequency of occurrence, Site G with two high tolerance turbines in parallel.

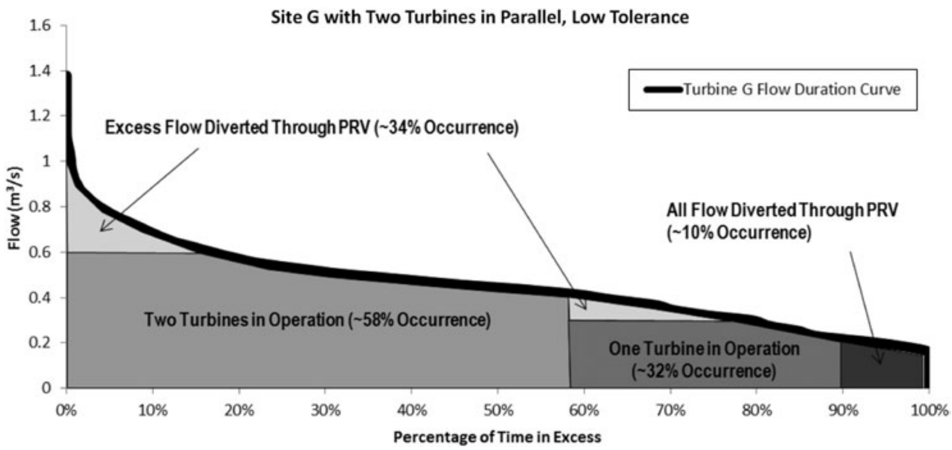

Figure 9. Modes of operation and frequency of occurrence, Site G with two low tolerance turbines in parallel.

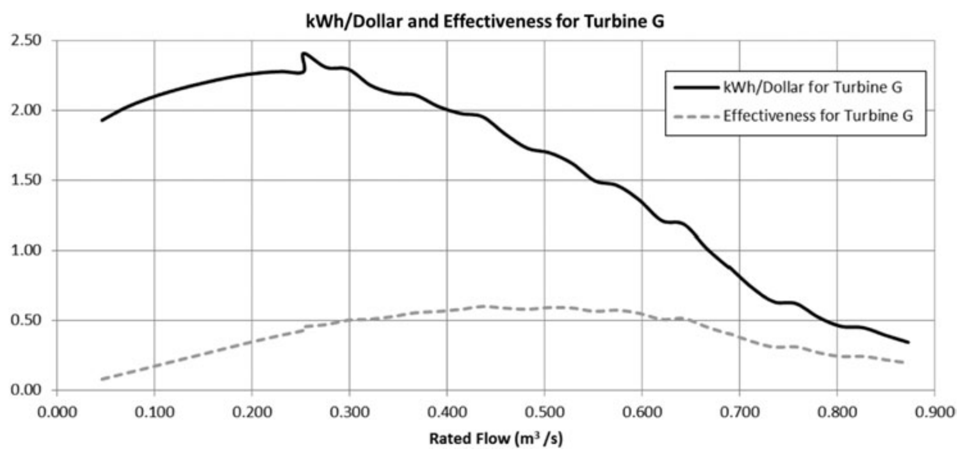

Figure 10. Comparison of turbine sizing based on kWh/Dollar and effectiveness for Turbine G.

Table 6. Comparison of turbine sizing based on kWh/Dollar and effectiveness.

	Maximum energy recovery			Maximum kWh/Dollar		
Region	Turbine size (kW)	Effectiveness	kWh/$	Turbine size (kW)	Effectiveness	kWh/$
D	9	0.57	0.35	4	0.42	0.52
E	369	0.59	2.08	213	0.45	2.54
G	188	0.60	1.96	109	0.46	2.41
H	17	0.57	0.52	8	0.42	0.78
I	11	0.55	0.88	6	0.41	1.18
J (series)	433	0.60	1.93	251	0.45	2.38
K (series)	297	0.59	1.84	172	0.45	2.24
J (direct)	136	0.60	1.70	79	0.45	2.10
K (direct)	594	0.59	2.80	344	0.45	3.42

more economically viable sites, the improvement is in the range of 20% to 30%. At a given site, a smaller turbine will operate with higher capacity factor than a larger one, which results in quicker recovery of capital costs. As in determining turbine system granularity, there is a dialectic relationship between present economic benefit and future energy recovery potential. However, it is the site potential rather than regional potential at stake in turbine sizing. A comparable trade-off is made in run-of-the-river hydro where only the portion of the site with the steepest gradient may be developed. Note that the cost function used in the developed method is based on estimates for installations in the 100 kW to 2 MW range (British Columbia Hydro and Power Authority, 2000); costs for smaller installations may be less accurate.

3.6 Broader considerations

The design principles discussed in the previous sections aid planners in evaluating and maximizing the economic feasibility and energy recovery potential of ERTs. It is worth to mention that energy recovery faces some practical challenges from a high-level perspective. ERTs are relatively rare and transform water distribution from a dedicated system that is solely a consumer of power to a multi-purpose system that both consumes and generates electricity; the transformation inevitably introduces complexities and unknowns. Furthermore, the core business of water utilities is maintaining a reliable supply of high quality water – not generating power. While electrical utilities compare ERTs against other power generation projects, water utilities face the difficult and multifaceted task of comparing ERTs against dissimilar projects such as fixing leaking pipes or improving water treatment processes. Clearly, the viability of energy recovery projects will be dictated by more than economic and technical feasibility.

4. Conclusion

The installation of ERTs in urban settings minimizes environmental impacts, leverages existing infrastructure, and requires lower capital investment relative to traditional hydroelectric power. Although challenges exist, ERTs can be an economical, flexible, and renewable option for controlling pressure and deserve serious consideration within some water supply systems. A case study based on Vancouver's water system shows that ERTs can be economically feasible. Economies of scale play an important role with the LCOE from $0.03/kWh to $0.04/kWh for installations larger than 100 kW; results indicate that economic feasibility deteriorates rapidly for smaller sites. Analyses of results further indicate that the economic feasibility of ERTs is predictably shaped by a variety of factors, including: water system geography and topography, water system pressure and leakage, turbine system granularity, location of service reservoirs, turbine flow tolerance, and turbine sizing objectives.

When designing a water system that will incorporate ERTs, planners should be aware of the trade-offs between turbine head, flow, and size. Planners should also be aware that piping friction losses and delivery pressure both have an appreciable impact on energy recovery potential. If possible, turbines should be located directly upstream of service reservoirs to decouple demand and turbine flow; results indicate an approximately 10% improvement in kWh/dollar for larger turbines and the prospect of dispatchable generation. Lastly, planners should consider the benefits of increased ERT flow tolerance and understand the perennial tension between maximizing economic benefit and preserving site and regional energy recovery potential. Results indicate kWh/dollar values may be improved by approximately 30% if a portion of site potential is sacrificed, and greater economies of scale may be leveraged at the cost of regional potential.

This study has investigated the influence of water system and turbine characteristics on ERT economic feasibility and developed general ERT design principles that will benefit infrastructure planners who may consider incorporation of ERTs into water systems.

Notations

η = turbine efficiency
C = annual cost of capital as a fraction of initial capital cost
d = density of water (kg/m^3)
D_p = penstock length (m)
D_t = transmission distance (m)
E_a = annual energy produced by turbine (J)
F_c = cost function
g = gravitational acceleration (m/s^2)
G = annual hydrograph (m^3/s)
H_d = delivery pressure (m)
H_p = total piping friction loss between reservoir and site (m)
H_r = turbine rated head (m)
H_s = site available turbine head (m)
H_{ut} = head of upstream turbines (m)
K_d = kWh/dollar (kWh/$)
L_p = peak elevation in the turbine's service area (m)
L_r = reservoir TWL (m)
M = annual maintenance cost as a fraction of initial capital cost
N = lifetime (years)
P_r = turbine rated power (kW)
Q_{max} = maximum turbine flow
Q_{min} = minimum turbine flow
Q_r = the turbine rated flow (m^3/s)
V_a = annual consumption volume (m^3)

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